NUREG-1434
Vol. 3

Standard Technical Specifications
General Electric Plants, BWR/6

Bases (Sections 3.4–3.10)

Draft Report for Comment

Issued by the
U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

January 1991

NUREG-1434, Vol. 3
Draft

STANDARD TECHNICAL SPECIFICATIONS
GENERAL ELECTRIC PLANTS, BWR/6

JANUARY 1991

NUREG-1434
Vol. 3

Standard Technical Specifications
General Electric Plants, BWR/6

Bases (Sections 3.4–3.10)

Draft Report for Comment

Issued by the
U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

January 1991

AVAILABILITY NOTICE

Availability of Reference Materials Cited in NRC Publications

Most documents cited in NRC publications will be available from one of the following sources:

1. The NRC Public Document Room, 2120 L Street, NW, Lower Level, Washington, DC 20555

2. The Superintendent of Documents, U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20013-7082

3. The National Technical Information Service, Springfield, VA 22161

Although the listing that follows represents the majority of documents cited in NRC publications, it is not intended to be exhaustive.

Referenced documents available for inspection and copying for a fee from the NRC Public Document Room include NRC correspondence and internal NRC memoranda; NRC Office of Inspection and Enforcement bulletins, circulars, information notices, inspection and investigation notices; Licensee Event Reports; vendor reports and correspondence; Commission papers; and applicant and licensee documents and correspondence.

The following documents in the NUREG series are available for purchase from the GPO Sales Program: formal NRC staff and contractor reports, NRC-sponsored conference proceedings, and NRC booklets and brochures. Also available are Regulatory Guides, NRC regulations in the Code of Federal Regulations, and Nuclear Regulatory Commission Issuances.

Documents available from the National Technical Information Service include NUREG series reports and technical reports prepared by other federal agencies and reports prepared by the Atomic Energy Commission, forerunner agency to the Nuclear Regulatory Commission.

Documents available from public and special technical libraries include all open literature items, such as books, journal and periodical articles, and transactions. Federal Register notices, federal and state legislation, and congressional reports can usually be obtained from these libraries.

Documents such as theses, dissertations, foreign reports and translations, and non-NRC conference proceedings are available for purchase from the organization sponsoring the publication cited.

Single copies of NRC draft reports are available free, to the extent of supply, upon written request to the Office of Information Resources Management, Distribution Section, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at the NRC Library, 7920 Norfolk Avenue, Bethesda, Maryland, and are available there for reference use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from the American National Standards Institute, 1430 Broadway, New York, NY 10018.

PREFACE

This DRAFT NUREG presents the results of the Nuclear Regulatory Commission (NRC) staff review of the BWR Owners Group (BWROG) proposed new Standard Technical Specifications (STS) for the BWR/6 design. These new STS were developed based on the criteria in the interim Commission Policy Statement on Technical Specification Improvements for Nuclear Power Reactors, dated February 6, 1987.

The new STS will be used as bases for developing improved plant-specific technical specifications by individual nuclear power plant owners that have BWRs designed by General Electric. The NRC staff is issuing this draft new STS for a 30 working-day comment period. Following the comment period, the NRC staff will analyze comments received, finalize the new STS, and issue them for plant-specific implementation.

Comments should be submitted no later than March 15, 1991, in accordance with the following guidance: The exact wording of each proposed change should be marked in pen and ink on copies of all the affected pages of DRAFT NUREG-1434, "Standard Technical Specifications, General Electric Plants, BWR/6." Each proposed change should be numbered. Each proposed change should be accompanied with a separate technical justification, cross referenced to the applicable proposed change on the marked up pages.

Submit written comments to: David L. Meyer, Chief, Regulatory Publications Branch, Division of Freedom of Information and Publications Services, Office of Administration, U. S. Nuclear Regulatory Commission, Washington, DC 20555. Hand deliver comments to: 7920 Norfolk Avenue, Bethesda, Maryland, between 7:45 a.m. and 4:15 p.m. on Federal workdays.

(continued)

(continued)

DRAFT

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. It 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 one variable speed motor-driven recirculation pump, a flow control valve, and a motor-generator (MG) set to control pump speed and associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

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

(continued)

(continued)

BASES (continued)

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% rated power) without having to move control rods and disturb desirable flux patterns. Because of the negative reactivity addition when recirculation flow is decreased, reactor coolant pumps are tripped, resulting in a void buildup and rapid power reduction and offsetting any serious consequences that might occur in the unlikely event of an anticipated transient without scram.

Each recirculation loop is manually started from the control room. The M-G set provides 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. If a LOCA occurs with a flow mismatch between the two loops, the analysis conservatively assumes the pipe break is in the loop with the higher flow. The flow coastdown and core response are potentially more severe in this case, since the intact loop

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

is starting at a lower flow rate and the core response is the same as if both loops were operating at the lower flow rate. 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 for the [Unit Name] 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 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) requirements are modified accordingly (Ref. 3).

The transient analyses of Chapter 15 of the [Unit Name] 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 MINIMUM CRITICAL POWER RATIO (MCPR) requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System Average Power Range Monitor (APRM) instrument setpoints are also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR, MCPR, and APRM flow biased simulated thermal power setpoints for single loop operation are specified in the CORE OPERATING LIMITS REPORT.

The above analyses are for Design Basis Accidents (DBAs) and transients that establish the acceptance limits for recirculation loop operation. Reference to the analyses for these DBAs and transients is used to assess changes to recirculation loop operation as they relate to the acceptance limits.

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

(continued)

BASES (continued)

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 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), MCPR Limits (LCO 3.2.2) and APRM Flow Biased Simulated Thermal Power—High setpoint (LCO 3.3.1) may be 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 one recirculation loop not in operation, the non-operating loop must be returned to operation 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.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

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

This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large flow mismatches occur, low flow or reverse flow can occur in pumps. If zero or reverse flow is detected, the condition should be alleviated by changing pump speeds to reestablish forward flow or by tripping the pump.

B.1

With no recirculation loops in operation, or a single loop not restored to operating status within the required Completion Time and the single loop requirements of the LCO not applied, the reactor is required to be placed in a MODE in which the LCO does not apply. This is done by placing the plant in 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 is reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Verification that the recirculation loop flows are ≤ [10]% of rated core flow when operating at < [70]% of rated core flow and at ≤ [5]% core flow at ≥ [70]% of rated core flow every 24 hours when both loops are in operation will assure against loop flow mismatch. At low core flow (i.e., < 70% 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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.

[For this facility, jet pump flows are measured as follows:]

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 24-hour Frequency is consistent with the Surveillance Frequency for jet pump operability verification and has been shown by operating experience to be adequate to detect off-normal jet pump loop flows in a timely manner.

REFERENCES

1. [Unit Name] FSAR, Section [6.3.3.4.], "[Title]."

2. [Unit Name] FSAR, Section [5.5.1.4.], "[Title]."

[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, 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.

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 stroking rate is limited to ≤ 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 (Ref. 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 stroke per second (Ref. 3).

The above analyses are for Design Basis Accidents (DBAs) that establish the acceptance limits for the FCVs. Reference to these analyses is used to assess changes to the FCVs as they relate to the acceptance limits.

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

(continued)

BASES (continued)

LCO

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

The FCV is considered OPERABLE when the requirements of SR 3.4.2.1 and SR 3.4.2.2 are met.

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

<u>A.1 and B.1</u>

With a FCV 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 within 4 hours.

Opening a FCV faster than the limit could result in a more severe flow runout transient resulting in violation of the Safety Limit MINIMUM CRITICAL POWER RATIO (MCPR). Closing a FCV faster than the limit characteristics assumed in the LOCA analysis (Ref. 3) could affect the recirculation flow coastdown resulting in higher peak clad temperatures. Therefore, if a FCV is inoperable due to stroke times faster than the limits, deactivating the valve will essentially lock the valve in position, which will prohibit the FCV from adversely affecting the DBA or 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.

The plant must be placed in a MODE in which the LCO does not apply if the FCVs cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours. This

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

places the plant in a condition where the flow coastdown characteristics of the recirculation loop are not important. The allowed Completion Time is based on operating experience to reach the required MODE from full power in an orderly manner and without challenging plant 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 was developed considering plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. Operating experience has shown these components virtually always pass the SR when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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 was developed considering plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. Operating experience has shown these components virtually always pass the SR when performed on Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. [Unit Name] FSAR, Section [15.3.2.], "[Title]."
2. [Unit Name] FSAR, Section [15.4.5.], "[Title]."
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, which discusses the operating characteristics of the system and how these characteristics affect the design basis accident 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 ten jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the 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.

APPLICABLE SAFETY ANALYSES

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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

establishes the acceptance limits for the jet pumps. Reference to this analysis is used to assess changes to the jet pumps as they relate to the acceptance limits.

The capability of reflooding the core 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 Interim 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 Recirculation System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1). For a jet pump to be OPERABLE it must satisfy either criteria of SR 3.4.3.1.

APPLICABILITY

The jet pumps are required to be OPERABLE in MODES 1 and 2 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 Recirculation System (LCO 3.4.1).

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

(continued)

BASES (continued)

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding during a design basis LOCA. If the jet pumps cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in MODE 3 in which the LCO does not apply. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

The Completion Time of Required Action A.1 contains a Note to clarify that all jet pumps are treated as an entity with a single Completion Time, i.e., the Completion Time is on a Condition basis.

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).

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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

recirculation pump discharge and jet pump nozzle. For this criterion, the loop versus FCV position relationship must be verified.

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 seen as an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations for 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.

[For this facility, jet pump flow is measured as follows:]

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

This SR is not required to be performed when THERMAL POWER is ≤ 25% of RATED THERMAL POWER. During low flow conditions, jet pump noise approached the threshold response of the associate flow instrumentation and precludes the collection of repeatable and meaningful data.

(continued)

(continued)

BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [6.3], "[Title]."
2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1990.
3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety/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 zero 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. Eight of the S/RVs that provide the relief function are part of the Automatic Depressurization System specified in LCO 3.5.1. The instrumentation associated with the relief valve function is discussed in the Bases for LCO 3.3.6.5.

(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. 1). 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 analyses 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.

Reference 2 discusses additional events which are expected to actuate the S/RVs. From an overpressure standpoint, these events are bounded by the MSIV closure with flux scram event described above.

Safety/Relief Valves satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

Seven S/RVs are required to be OPERABLE in the safety mode, and an additional six S/RVs (other than the seven S/RVs that satisfy the safety function) must be OPERABLE in the relief mode. To be operable, a valve must be properly set to open at the required pressure and have met its surveillance requirements. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure. In Reference 1, 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

(continued)

(continued)

BASES (continued)

LCO (continued)

not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in Reference 2 are based on these setpoints, but also include the additional uncertainties of ± 1% of the nominal setpoint to account for potential setpoint drift and to provide an added degree of conservatism.

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

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 remove, and reactor pressure is low enough that the overpressure limit cannot 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 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 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.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

The 14-day Completion Time to restore the inoperable S/RVs to OPERABLE status is based on the 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.

B.1 and B.2

With less than the minimum number of S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of the inoperable S/RVs cannot be restored to OPERABLE status within the associated Completion Time or if the safety function of three or more S/RVs are inoperable, the plant must be placed in a mode in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required modes from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR demonstrates that the S/RVs will open at the pressures assumed in the safety analysis of Reference 1. [For this facility] These pressure settings are as follows: [ ] psig. The demonstration of the S/RV lift settings must be performed during shutdown, since this is a bench test, and in accordance with the provisions of SR 3.0.5. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

The 18-month Frequency was selected because this Surveillance must be performed during shutdown conditions, and is based on the refueling cycle.

SR 3.4.4.2

A manual actuation of each 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

or bypass valve, 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. Sufficient time is therefore allowed after the required pressure is achieved to perform this test. Adequate pressure at which this test is to be performed is 920 psig (the pressure recommended by the valve manufacturer). 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. If the valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the S/RV is considered OPERABLE.

The 18-month Frequency is consistent with SR 3.4.4.1 to ensure that the S/RVs are manually actuated following removal for refurbishment or lift setting testing.

The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for test and provides adequate time to reasonably complete the SR.

REFERENCES

1. [Unit Name] FSAR, Section [5.2.2.6.3], "[Title]."

2. [Unit Name] FSAR, Section [15], "[Title]."

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 and the methods used to identify and quantify it.

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

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

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

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)	violating this LCO include the possibility of a loss-of-coolant accident (LOCA).
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. 3 and 4) shows leak rates of hundreds of gpm will precede crack instability (Ref. 5). The above analyses establish the acceptance limits for RCS operational LEAKAGE. Reference to these analyses is used to assess changes to the facility which could affect operational LEAKAGE as they relate to the acceptance limits. 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 Interim Policy Statement.

(continued)

BASES (continued)

LCO

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.

b. Unidentified LEAKAGE

Five gallons per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring, drywell sump level monitoring, and containment 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 in any 24-hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady-state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2-gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCOs apply because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized. Therefore, detection of RCPB LEAKAGE is required during MODES 1, 2, and 3.

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.

A Note has been included to provide clarification that Conditions A, B, and C are treated as an entity with a single Completion Time.

ACTIONS

A.1 and B.1

With either the unidentified LEAKAGE, the total LEAKAGE, or both greater than the required limits, Actions must be taken to identify the source and determine the significance of the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours are allowed to verify and reduce the LEAKAGE rates before the reactor must be shut down. If a change in unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE. However, the total LEAKAGE limit would remain unchanged.

C.1 and C.2

An unidentified LEAKAGE increase of 2 gpm in a 24-hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated.

Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE within the required Completion Time. 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 must be evaluated and eliminated as the source of the increased LEAKAGE. This piping is very susceptible to IGSCC.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Alternatively, the LEAKAGE rate must be restored to within limits within the required Completion Time.

The 4-hour Completion Time is needed to properly verify the source or reduce the LEAKAGE increase before the reactor must be shut down.

D.1 and D.2

If any one of the Required Actions A.1, B.1, and C.1 or C.2 cannot be met within the 4-hour Completion Time, the reactor must be placed in a MODE in which the LCO does not apply: in 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 MODES from full power in an orderly manner and without challenging plant safety 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. 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 2. 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 trends.

SR 3.4.5.2

The leaktight integrity of the RCPB is verified by visual inspection. The Inservice Testing Program and operational hydrostatic tests at normal operating pressure are acceptable means of verifying no RCPB LEAKAGE. The 18-month Frequency is based on the refueling cycle and adequately verifies RCPB integrity.

(continued)

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 30, "Quality Of Reactor Coolant Pressure Boundary."
2. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. GEAP-5620, "Failure Behavior in ASTM A106 Pipes Containing Axial Through-Wall Flaws," April 1968.
4. NUREG-76/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975.
5. [Unit Name] FSAR, Section [5.2.5.5.3.], "[Title]."

DRAFT

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50 Appendix A (Refs. 1, 2, & 3) define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB) that separate the high pressure RCS from an attached low pressure system. 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 3.4.4.

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.

The basis for this LCO is the 1975 Reactor Safety Study (Ref. 5) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 6) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This later study concluded that periodic leak testing of the PIVs can substantially reduce

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

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;

c. High Pressure Core Spray System; and

d. Reactor Core Isolation Cooling System.

The PIVs are listed in Reference 7.

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.

APPLICABLE SAFETY ANALYSES

Reference 5 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is [the failure of the low pressure portion of the RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is typically designed for [800] psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.]

Reference 6 evaluated various PIV configurations, leak testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leak testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

Leakage from the PIVs is a factor in the dose rates that are used in safety and accident analyses. Therefore, the leakage must be maintained within LCO limits to ensure assumptions used in the analyses are valid.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

PIV leakage is not considered in any Design Basis Accident analyses, however. 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, which has not been analyzed. Compliance with this LCO ensures that an unanalyzed Condition will not be entered. Therefore RCS PIV Leakage satisfies Criterion 2 of the NRC Interim 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.

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 LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm (Ref. 8). The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leak rate limit based on valve size was superior to a single allowable value.

Reference 8 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 is 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 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.

A Note has been added to provide clarification that each flow path is independent and is treated as a separate entity with a separate Completion Time for the purpose of this LCO.

ACTIONS

A.1, A.2.1, and A.2.2

Four hours are provided to reduce leakage in excess of the allowable limit. The period permits operation to continue under stable conditions while corrective actions to reseat the leaking PIVs are taken. The 4 hours allow these Actions and restrict the time of operation with leaking valves.

Alternatively, the flow path must be isolated by two other valves. Required Action A.2.1 and Required Action A.2.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB.

Required Action A.2.1 requires that the initial isolation with one valve must be performed within 4 hours of exceeding the limit. This 4-hour Completion Time is based on the same rationale as the time for Required Action A.1.

Required Action A.2.2 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 time after exceeding the limit considers the time required to complete the Action and the low probability of a second valve failing during this time period.

RCS PIV leakage is considered out of limits if the equipment used to measure RCS PIV leakage is determined to be inoperable at the time SR 3.4.5.1 is performed. Required

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Action A.1 or Required Action A.2.1. and Required Action A.2.2 apply to restoring such equipment to OPERABLE status.

B.1 and B.2

If leakage cannot be reduced or the system isolated, the RCS must be placed in a MODE in which the requirement does not apply. This is done by placing the plant in MODE 3 within 12 hours and 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 MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.2.1 or Required Action A.2.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

[For this facility, RCS PIV or isolation valve leakage is measured as follows:]

Testing is to be performed every 9 months, but may be extended up to a maximum of 18 months, a typical refueling cycle, if the plant does not go into MODE 4 for at least 7 days. The 18-month Frequency required in 10 CFR 50.55a(g) (Ref. 9), is within the American Society of Mechanical Engineers (ASME) Code, Section XI Frequency requirement (Ref. 10), and is based on the prudence of performing Surveillances such as this only during an outage. The Surveillance needs stable conditions and has the potential for an unplanned plant transient if performed with the plant at power.

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

SR 3.0.4 is excepted for entry into MODE 3 to permit leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Section 50.2, "Definitions—Reactor Coolant Pressure Boundary."

2. Title 10, Code of Federal Regulations, Part 50, Section 50.55a, "Codes and Standards," Subsection (c), "Reactor Coolant Pressure Boundary."

3. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section V, "Reactor Containment," General Design Criterion 55, "Reactor Coolant Pressure Boundary Penetrating Containment."

4. ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants."

5. U.S. Nuclear Regulatory Commission (NRC), "Reactor Safety Study—An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," Appendix V, WASH-1400 (NUREG-75/014), October 1975.

6. U.S. NRC, "The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes," NUREG-0677, May 1980.

7. [ ]

(continued)

(continued)

BASES (continued)

REFERENCES (continued)

8. ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants," Paragraph IWV-3423(e).

9. Title 10, Code of Federal Regulations, Part 50, Section 50.55a, "Codes and Standards," Subsection (g), "Inservice Inspection Requirements."

10. ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants," Paragraph IWV-3422.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS LEAKAGE Detection Instrumentation

BASES

BACKGROUND

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

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). LEAKAGE detection systems for the RCS are provided to alert the operators when LEAKAGE rates above normal background levels are detected and also to supply quantitative measurement of LEAKAGE rates. The Bases for LCO 3.4.5 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 sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, 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. If the sump fills to the high level setpoint before t

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

timer ends, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of present 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 air 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 which 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). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

RCS LEAKAGE detection instrumentation satisfies Criterion 1 of the NRC Interim 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.

[For this facility, OPERABLE LEAKAGE detection instrumentation consists of the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure LEAKAGE detection instrumentation OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the LEAKAGE detection instrumentation inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, LEAKAGE detection systems are required OPERABLE to support LCO 3.4.5, "RCS Operational LEAKAGE." This applicability is consistent with that for LCO 3.4.5.

ACTIONS

A.1, A.2.1 and A.2.2

With the drywell floor drain sump monitoring system inoperable, no other form of sampling can provide the equivalent information. However, the atmospheric activity monitor does provide [(or) and the drywell air cooler condensate flow rate monitor] indication of changes in

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

LEAKAGE. Twenty-four hours are allowed to restore the drain sump monitoring system to OPERABLE status or Condition E must be entered. Twenty-four hours limits the time that operation can continue without the ability to measure the leakage rate and establish compliance with the LEAKAGE limits. Alternatively leakage rate may be determined by manually pumping the sump or by measuring the sump level differences every four hours. If neither of these two methods are available, Condition E must be entered since leakage cannot be quantified.

With the drywell floor drain sump monitoring system inoperable, but with leakage rate being measured by manually pumping the sump or measuring sump level differences, operation may continue for 30 days. The 30 days allow sufficient time to repair the system and recognizes that a method to quantify leakage rate is available, but prevents operation of the plant for a long period with a degraded leakage detection system.

B.1 and B.2

With the required primary containment atmospheric particulate and gaseous monitoring system inoperable, grab samples of the containment atmosphere shall be taken and analyzed to provide periodic information. Provided a sample is obtained and analyzed every 12 hours, the plant may continue operation for up to 30 days.

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 leak detection is available.

[C.1]

[With the required primary containment air cooler condensate flow rate monitoring system inoperable, samples shall be taken and analyzed every 12 hours to provide periodic information. The 12-hour interval provides periodic information that is adequate to detect LEAKAGE and recognizes that other forms of leak detection are available.]

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

[D.1 and D.2]

[With the containment atmosphere radioactivity monitor and the containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the containment 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 days completion time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.]

E.1 and E.2

If a Required Action of A, B, C, or D cannot be met within the required Completion Time, the reactor must be placed in a MODE in which the LCO does not apply. This requires placing the reactor in at least MODE 3 within 12 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable based on operating experience to perform the actions in an orderly manner and without challenging plant systems.

F.1

With all required monitors inoperable, no 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, SR 3.4.7.2, and SR 3.4.7.3

These SRs are the performance of a CHANNEL CHECK of each of the RCS LEAKAGE detection monitors. The check gives reasonable confidence that each channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off-normal conditions. For this facility, a CHANNEL CHECK consists of [ ].

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.4, SR 3.4.7.5, and SR 3.4.7.6

These SRs are the performance of a CHANNEL FUNCTIONAL TEST on each of the RCS LEAKAGE detection monitors. The test ensures that the monitor can perform its function in the desired manner. The test 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. For this facility, a CHANNEL FUNCTIONAL TEST consists of [ ].

SR 3.4.7.7, SR 3.4.7.8, and SR 3.4.7.9

These SRs are the performance of a CHANNEL CALIBRATION for each of the RCS LEAKAGE detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The frequency of [18 months] is a typical refueling cycle and considers channel reliability. Again, operating experience has proven this frequency is acceptable. For this facility, a CHANNEL CALIBRATION consists of [ ].

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix A, Section IV, "Fluid Systems," General Design Criterion 30, "Quality of Reactor Coolant Pressure Boundary."

2. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

3. [Unit Name] FSAR, Section [5.2.5.2.], "[Title]."

4. GEAP-5620, "Failure Behavior in ASTM A106 Pipes Containing Axial Through-Wall Flows," April 1968.

5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975.

6. [Unit Name] FSAR, Section [5.2.5.5.3.], "[Title]."

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 both iodine and total specific activity limits. The iodine isotopic activities are expressed in terms of a DOSE EQUIVALENT I-131 per gram of reactor coolant. Total specific reactor coolant activity is limited on the basis of the weighted average beta and gamma energy levels in the coolant. 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 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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

body doses at the site boundary, resulting from an MSLB outside containment during steady-state operation, will not exceed 10% of the dose guidelines of 10 CFR 100. This is the acceptance limit for the MSLB analysis.

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 Interim Policy Statement.

LCO

The specific iodine activity is limited to 0.2 μCi/gm DOSE EQUIVALENT I-131, and the total specific activity is limited to 100/Ē μCi/gm. These limits ensure 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 coolant to the environment in the event of an MSLB outside of primary containment.

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

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is less than or equal to 4.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

I-131 at least every 4 hours. In addition, the specific activity must be restored to the LCO limit in 48 hours.

The Completion Time of once every 4 hours is 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.

DOSE EQUIVALENT I-131 specific activity is considered out of limits if the equipment used to measure DOSE EQUIVALENT I-131 specific activity is determined to be inoperable at the time SR 3.4.8.2 is performed. Required Action A.1 and Required Action A.2 apply to restoring such equipment to OPERABLE status.

B.1 and B.2

If the DOSE EQUIVALENT I-131 cannot be restored to less than or equal 0.2 μCi/gm within 48 hours, or if at any time it is greater that 4.0 μCi/gm, it must be determined at least every 4 hours and 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 more than a small fraction of the requirements of 10 CFR 100 during a postulated MSLB accident.

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.

C.1

When the reactor coolant specific activity is greater than $100/\bar{E}$ μCi/gm, the reactor must be placed in MODE 3 with all main steam lines isolated within 12 hours. The required MODE 3 operation ensures the reactor is subcritical. Closing the MSIVs eliminates the potential radioactivity release path to the environment during the MSLB event.

The 12-hour Completion Time is reasonable, based on operating experience, to reach MODE 3 from full power and to

(continued)

(continued)

BASES (continued)

ACTIONS (continued)	isolate the main steam lines in an orderly manner and without challenging plant systems.
	Gross specific activity is considered out of limits if the equipment used to measure gross specific activity is determined to be inoperable at the time SR 3.4.8.1 is performed. Required Action C.1 applies to restoring such equipment to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

The Surveillance requires performing a gamma-isotopic analysis as a measure of the gross specific activity of the reactor coolant at least once per 7 days. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with RCS average temperature at least 500°F. The 7-day Frequency considers the unlikelihood of a gross fuel failure during the time.

SR 3.4.8.2

This Surveillance is performed, in MODE 1 only, to ensure iodine remains within limit during normal operation, and following fast power changes when fuel failure is more apt to occur. The 14-day Frequency is adequate to trend changes in the iodine activity level considering gross activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change of greater than or equal to 15% RATED THERMAL POWER within a 1-hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

[For this facility, DOSE EQUIVALENT I-131 specific activity is measured as follows:]

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.3

A radiochemical analysis for $\bar{E}$ determination is required every 184 days (6 months) with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. Operating experience has shown that $\bar{E}$ does not change rapidly and the Frequency of 184 days recognizes this.

Note 1 states that SR 3.0.4 does not apply so sampling can be performed in MODE 1. Note 2 requires that the sample be taken after 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance," 1973.

2. [Unit Name] FSAR, Section [15.1.40], "[Title]."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Residual Heat Removal (RHR)—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 and maintain the temperature of the reactor coolant to ≤ 200°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the conditions for cold shutdown operation.

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 the associated recirculation loop. The RHR heat exchangers transfer heat to the Standby Service Water System (LCO 3.7.1).

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. Those LCOs that operating experience and probabilistic risk assessment have generally shown to be important to public health and safety are retained as Technical Specifications.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one 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 subsystem is considered OPERABLE if it can be manually aligned (remote

(continued)

(continued)

BASES (continued)

LCO (continued)

or local) in the shutdown cooling mode for removal of decay heat. In MODES 3 and 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.

An RHR pump is OPERABLE when it is capable of being powered and able to provide flow if required.

[For this facility, the following support systems are required to be OPERABLE to ensure RHR shutdown cooling subsystem OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the RHR shutdown cooling subsystems inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure above the RHR cut-in permissive pressure, this LCO is not applicable. Under these conditions, the permissive does not allow placing the low-pressure RHR shutdown cooling subsystem into operation. 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 above the RHR cut-in permissive pressure is typically accomplished by boiling in the core and condensing the steam in the main condenser.

In MODE 3 with reactor steam dome pressure below the RHR cut-in permissive pressure ([ ] psig), and in MODE 4, the RHR System may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature.

The requirements for decay heat removal in MODE 5 are discussed in LCO 3.9.8 and LCO 3.9.9.

The Note permits both RHR shutdown cooling subsystems to be shut down for a period of 2 hours in an 8-hour period, provided that one subsystem is OPERABLE and the coolant temperature remains below 200°F. The margin to boiling

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

should be low enough that the time anticipated for being without forced RCS flow will be less than 2 hours and not long enough for the coolant temperature to reach 200°F. When this temperature is approached, the OPERABLE RHR subsystem must be placed in service. 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 without violating the LCO.

ACTIONS

A.1, A.2.1, A.2.2, and A.2.3

With one RHR shutdown cooling subsystem inoperable for decay heat removal, the inoperable subsystem must be restored to OPERABLE status within 8 hours. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability.

An alternative to Required Action A.1 is to establish an alternate method of decay heat removal within 8 hours. This alternative method need not be safety grade; however, if it is not, a safety-grade method must be demonstrated OPERABLE within 24 hours. 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 contributing to the alternate method capability.

[One alternate safety-grade shutdown cooling method is pumping water from the suppression pool through a RHR heat exchanger and into the reactor vessel through a low pressure coolant injection flow path. A cooling loop back to the suppression pool could use the main steam safety relief valves and their discharge piping. This method uses safety-grade, seismically qualified, and environmentally qualified equipment that can withstand a loss of offsite power. Alternate methods could use the Spent Fuel Pool Cooling System or the Reactor Water Cleanup System.]

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

The 8-hour Completion Time to either restore the RHR shutdown cooling subsystem or establish an alternate method of decay heat removal is based on the importance of the RHR shutdown cooling function, the level of redundancy provided, and a reasonable time to complete the Required Action.

The 24-hour Completion Time to demonstrate an alternate safety-grade decay heat removal method OPERABLE provides sufficient time to perform tests or analyses, while limiting operation with the loss of safety-grade redundancy for the decay heat removal function.

Since the alternate method of removing decay heat may not be as reliable, overall, as the RHR shutdown cooling subsystem, the inoperable RHR shutdown cooling subsystem must be returned to OPERABLE status within 14 days. The 14-day Completion Time is based on the importance of the shutdown cooling function and limits the time of operation with an alternate method of shutdown cooling, yet allows time for repair of the RHR shutdown cooling subsystem.

B.1, B.2.1, B.2.2, and B.2.3

If one inoperable RHR shutdown cooling subsystem cannot be restored to OPERABLE status within the associated Completion Time, or if both subsystems are inoperable, action must be taken immediately to restore one RHR shutdown cooling subsystem to OPERABLE status or establish an alternate method of decay heat removal for each inoperable subsystem.

Again, if the alternate methods are not safety-grade, a safety-grade alternative for each inoperable subsystem must be demonstrated OPERABLE, by test or analysis, within 24 hours. (The discussion for alternate methods under Required Action A.1, Required Action A.2.1, Required Action A.2.2, and Required Action A.2.3 also applies here.)

In addition to the alternate method process, one RHR shutdown cooling subsystem must be restored to OPERABLE status within 72 hours.

Immediate action ensures that decay heat removal is available at all times and signifies the importance of beginning restoration without delay and continuing until a method of decay heat removal is established. The basis

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

for the 24-hour Completion Time is the same as for Required Action A.2.2. The 72-hour Completion Time for restoring one subsystem to OPERABLE status considers the importance of having at least one subsystem OPERABLE and the restoration time.

C.1, C.2.1, C.2.2, C.2.3, and C.2.4

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by the Applicability Note, forced reactor coolant circulation must be restored or an alternate method must be established within 2 hours. Restoration of forced circulation requires one RHR shutdown cooling subsystem or one recirculation pump placed in operation. If the alternative method is used, the reactor coolant temperature and pressure must be monitored hourly.

As before, if the alternate method is not safety grade, a safety-grade alternative must be proven OPERABLE within 24 hours. (The discussion for alternate methods under Required Action A.1, Required Action A.2.1, Required Action A.2.2, and Required Action A.2.3 again applies here.)

In addition to the alternate method process, one RHR shutdown cooling subsystem or one recirculation pump must be restored to operation within 72 hours.

The 2-hour Completion Time considers the time necessary to re-establish forced circulation and prevent boiling away coolant that could lead to fuel failure and spread of radioactive contamination and could require significant makeup to the RCS. The hourly Completion Time for monitoring of temperature and pressure provides adequate warning of potential problems without forced coolant circulation. The basis for the 24-hour Completion Time is the same as for Required Action A.2.2. The 72-hour Completion Time is reasonable for restoration of a subsystem or a recirculation pump to operation without relying on an alternate method of heat removal for an extended time.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

The 31-day Frequency of this SR is based on Inservice Testing Program requirements to perform valve testing at least once every 92 days. This SR does not require any testing or valve manipulation; rather, it involves verification by means of system walkdown that those valves outside containment and not locked, sealed, or otherwise secured in position can be aligned to their correct position. Since these valves are readily accessible to personnel during normal plant operation and verification of their position is relatively easy, the 31-day Frequency was chosen to provide additional assurance that the valves are in the proper position. Because some of the required valves are interlocked closed when above the RHR cut-in permissive pressure, an allowance is provided to test the valves within 12 hours after pressure has been reduced below the cut-in permissive pressure. This allows conditions to be established under which the test may be performed.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 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 P/T changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

LCO 3.4.10 contains P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic (ISLH) 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 loop 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).

Reference 1 addresses the concern that undetected flaws can exist in the RCPB components and can result in brittle (non-ductile) failure if subjected to unusual pressure or thermal stresses. Certain RCS P/T combinations can cause stress concentrations at flaw locations, which, in turn,

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

can cause flaw growth and result in failure before the ultimate strength of the material is reached. Material toughness resists and can even arrest flaw growth.

Material toughness varies with temperature and is less at room temperature than at operating temperature. Toughness also depends on the chemistry and impurities of the base material, weld material, and heat-affected zone material. Furthermore, neutron fluence affects material toughness by decreasing ductility; the effect accumulates, and the portion of the RCPB in a high fluence area, the vessel beltline region, steadily decreases in ductility with exposure time.

Linear elastic fracture mechanics (LEFM) methodology is used to determine the stresses and material toughness at locations within the RCPB. The LEFM methodology follows the guidance given by 10 CFR 50, Appendix G; ASME Section III, Appendix G; and Regulatory Guide 1.99 (Ref. 3). Although any place in the RCPB is subject to non-ductile failure, the more restrictive limits apply to the vessel beltline, the vessel closure head, and the vessel outlet nozzles. With increased neutron fluence, the vessel beltline, with base metals and welds, typically becomes the most restrictive region.

Material toughness properties of the ferritic materials of the reactor vessel are determined in accordance with the NRC Standard Review Plan (Ref. 4), the American Society for Testing Materials (ASTM) E 185 (Ref. 5), and additional reactor vessel requirements. These properties are then evaluated in accordance with Reference 2.

One indicator of the temperature effect on ductility is the nil-ductility temperature (NDT). The NDT is that temperature below which non-ductile fracture failure may occur. Ductile failure may occur above the NDT.

A range of NDT data points for the steel alloy used in reactor vessel fabrication has been established by testing, but the exact value of NDT cannot be determined. Therefore, a nil-ductility reference temperature (RT_{NDT}) has been established by experimental means. The neutron embrittlement effect on the material toughness is reflected by increasing the RT_{NDT} as exposure to neutron fluence increases.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

In effect, the temperature below which non-ductile failure can occur increases over time in operation. Reference 3 provides guidance for evaluating the effect of neutron fluence. To assist in evaluating the amount of RT_{NDT} shift to be applied, surveillance specimens, made up of samples of reactor vessel material, are placed near the inside wall of the reactor vessel in the beltline region.

As the RT_{NDT} increases with vessel exposure to neutron fluence and the material toughness decreases, the P/T limit curves are correspondingly adjusted. This gives limits that provide pressure boundary protection over the design life of the vessel. The effect of the RT_{NDT} shift is to cause the pressure limit to decrease at a given temperature.

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. 5) and Appendix H of 10 CFR 50 (Ref. 6). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 3.

This specification provides two types of limits:

a. Reactor coolant P/T curves that define allowable operating regions; and

b. Limits on the allowable rate of change of temperature of the reactor coolant, which affect the thermal gradients through the wall of the vessel and, thus, the tensile stresses in the wall.

In use, the P/T curves are primarily for prevention of non-ductile failure, whereas the limits on rate of change assist in preventing both ductile and non-ductile failures.

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

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

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 calculation to generate the ISLH testing curve uses different safety factors (per Ref. 2) than the heatup and cooldown curves. The ISLH testing curve also extends to the RCS design pressure of 2500 psia.

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 ISLH testing.

The P/T limit curves and associated temperature rate-of-change limits are developed in conjunction with stress analyses for large numbers of operating cycles and provide conservative margins to non-ductile failure. Although created to provide limits for these specific normal operations, the curves also can be used to determine if an evaluation is necessary for an abnormal transient.

The consequence of violating the LCO limits is that the RCS has been operated under conditions that could have resulted in brittle failure of the RCPB, possibly leading to a non-isolable 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. 7) 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 non-ductile failure of the RCPB, a

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

condition which is unanalyzed. Reference 8 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 are acceptance limits themselves since they preclude operation in an unanalyzed condition.

The analyses comprise a number of steps that establish the limits. Following are the basic elements:

a. Define the temperature profile. The reactor coolant temperature rate of change is defined so that normal plant operation can readily proceed without constraint. Cooldown and ISLH testing rates of change are similarly defined. These rates of change become LCO limits, as well as the bases for the heat transfer calculations.

b. Perform heat transfer calculations. The results determine the thermal gradient through the vessel wall. The analyses account for variances in flow rate and the consequent changes in the rate of heat transfer between the reactor coolant and the wall during different stages of heatup and cooldown.

c. Establish the material toughness as a function of RT_{NDT}. ASME Section III, Appendix G provides the basis for RT_{NDT}, and Regulatory Guide 1.99 provides the basis for adjusting RT_{NDT} as a function of neutron fluence and material constituents and impurities.

d. Perform a LEFM analysis to establish the P/T limits. The criterion for setting the limits is that the combined P/T stresses cannot exceed the material toughness for the specific temperature under examination. The analytical stress concentration at each location is driven by postulating specific flaw sizes. Stress intensity factors for P/T are calculated and compared to a reference stress intensity factor. Safety factors are applied to the pressure stress intensity factor.

With the material toughness established as a function of RT_{NDT}, stress analyses are performed per Reference 2 to set the P/T limits. The limiting location of

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

maximum stress may vary during heatup or cooldown operations, depending on pressure, temperature, and temperature rates of change.

Thus, the heatup and cooldown curves are composites of the limiting pressures at specific temperatures, with separate curves derived for varying heatup and cooldown rates.

c. Adjust the curves. The curves are adjusted for differences in elevation between the instrument tap locations and the vessel beltline and for system pressure losses at different stages of heatup or cooldown. The limit curves are also adjusted for the estimated instrument errors of the wide-range P/T instruments.

The P/T limit curves must account for a requirement from Reference 1 that the minimum temperatures of the closure head flange and vessel flange regions must be at least 120°F above the limiting RT_{NDT} for these regions when the pressure exceeds 20% of the preservice hydrostatic test pressure.

The calculation assumes a semi-elliptical surface defect with a depth of one-quarter of the wall thickness, $\frac{1}{4}$ T, and a length of $\frac{3}{2}$ T exists first at the inside of the vessel wall, then at the outside of the vessel wall. These dimensions are well within the current detection capabilities of inservice inspection techniques. Therefore, the P/T limit curves developed for this postulated defect are conservative and provide adequate protection against non-ductile failure.

To ensure that the radiation embrittlement effects on the RT_{NDT} are accounted for in the calculations for the limit curves, the most limiting RT_{NDT} (of the various reactor vessel components) is used and includes a radiation-induced shift corresponding to the end of the fluence period for which heatup and cooldown curves are generated. This shift is a function of both the neutron fluence and the copper and nickel contents of the vessel material. The heatup and cooldown P/T limit curves include predicted adjustments for

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

the RT_{NDT} shift and state the number of effective full power years for which this shift applies.

The actual shift in RT_{NDT} of the beltline region material will be established periodically during operational history by removing and evaluating the irradiation surveillance specimens installed near the inside wall of the reactor vessel in the core area. Since the neutron spectra at the irradiation samples and at the vessel inside wall are essentially identical, the measured transition shift for a sample can be applied to the adjacent section of the reactor vessel. The limit curves must be recalculated when the actual RT_{NDT} from the surveillance specimens is higher than the calculated RT_{NDT} for the presumed radiation exposure.

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

LCO

The elements of this LCO are:

a. RCS pressure, temperature, and heatup or cooldown rate are within the limits specified in LCO 3.4.10.

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is within the limit of the PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) during recirculation pump startup.

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 pump startup.

d. RCS P/T are within the criticality limits specified in the PTLR.

e. The reactor vessel flange and the head flange temperatures are within the limits of the PTLR when reactor vessel head bolting studs are tensioned.

(continued)

(continued)

BASES (continued)

LCO (continued)

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to non-ductile 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 ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

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

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 RCS P/T limits LCO provides a definition of acceptable operation for prevention of non-ductile (brittle) failure in accordance with 10 CFR 50, Appendix G (Ref. 1). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3 and 4) or ISLH testing, their applicability is at all times in keeping with the concern for non-ductile failure.

During MODES 1 and 2, other LCOs provide limits for operation that can be more restrictive than these P/T limits. These LCOs are LCO 3.4.1, "Recirculation Loops Operating," and LCO 3.4.11, "Reactor Steam Dome Pressure." Safety Limit 2.1, "Safety Limits," also gives operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for non-ductile failure, and

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

The Actions designated by this specification are based on the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, which may be accompanied by equipment failures, may also require additional Actions based on emergency operating procedures.

<u>A.1 and A.2</u>

Operation not within the P/T limits must be restored to within the limits. The RCPB must be placed in a condition that has been verified by stress analyses. Restoration is in the proper direction to reduce RCPB stress.

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 before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components. The evaluation must be completed, documented, and approved in accordance with established plant procedures and administrative controls.

ASME 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 evaluation must extend to all components of the RCPB.

The 72-hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

special, event-specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring both Required Action A.1 and Required Action A.2 completed whenever the restore operation within limits and perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone is insufficient because higher-than-analyzed stresses may have occurred and may have affected the RCPB integrity.

The combination of RCS P/T is considered out of limits if the equipment used to measure RCS pressure or temperature is determined to be inoperable. Required Action A.1 and Required Action A.2 apply to restoring such equipment to OPERABLE status.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused drastic 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 conditions, the possibility of propagation of undetected flaws is decreased.

If the restoration activity cannot be accomplished in 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce P/T.

If the evaluation for continued operation cannot be accomplished in 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed, documented, and approved before returning to operating P/T conditions. However, if the favorable evaluation is accomplished while reducing P/T conditions, a return to power operation may be considered without completing Required Action B.1 and Required Action B.2.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

P/T are reduced by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

The 36-hour Completion Time for achieving MODE 5 permits a soak period, if needed, or a slower cooldown [(~5°F/hr)]. A soak period may be desirable if a temperature rate of change limit has been violated.

SURVEILLANCE REQUIREMENTS

<u>SR 3.4.10.1</u>

Verification that operation is within LCO limits is required every 30 minutes when RCS P/T 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 permit assessment and correction of minor deviations.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

A Note requires this Surveillance to be performed only during system heatup, cooldown, and ISLH testing.

[For this facility, RCS P/T is measured as follows:]

<u>SR 3.4.10.2 and SR 3.4.10.3</u>

Differential temperatures within the applicable LCO 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. 9) are satisfied.

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

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

A Note requires SR 3.4.9.3 to be performed in MODES 1, 2, and 3, and in MODE 4 with reactor steam dome pressure ≤ 25 psig. A Note also requires SR 3.4.9.4 to be performed only in MODES 1, 2, 3, and 4.

[For this facility, bottom head coolant temperature is measured as follows:]

[For this facility, RPV coolant temperature is measured as follows:]

<u>SR 3.4.10.4</u>

A separate limit is used when the reactor is critical. Consequently, the RCS P/T must be verified within the appropriate limits before withdrawing control rods that might make the reactor critical.

Performing the surveillance within 15 minutes before 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.

<u>SR 3.4.10.5</u>

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require ensurance that these temperatures meet the LCO limits. Surveillances must be performed every 30 minutes while approaching and early in MODE 4, then every 12 hours until reaching the specified RCS temperature.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

The flange temperatures must be verified 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 less than or equal to 80°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 less than or equal to 100°F, Surveillances of the flange temperatures are 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. Title 10, Code of Federal Regulations, Part 50, Appendix G, "Fracture Toughness Requirements."
2. ASME Boiler and Pressure Vessel Code, Section III, Appendix G, "Protection Against Non-Ductile Failure."
3. Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988.
4. NUREG-0800, USNRC Standard Review Plan, Section 5.3.1, "Reactor Vessel Materials," Rev. 1, July 1981.
5. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," July 1982.
6. Title 10, Code of Federal Regulations Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements."
7. ASME Boiler and Pressure Vessel Code, Section XI, Appendix E, "Evaluation of Unanticipated Operating Events."

(continued)

(continued)

BASES (continued)

REFERENCES (continued)

8. NEDO-21778-A, "Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors," December 1978.

9. [Unit Name] FSAR, Section [15], "[Title]," [Subsection 15.1.26.]

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 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 ≤ [1020] 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 (MINIMUM CRITICAL POWER RATIO, see Bases for LCO 3.2.2) and 1% cladding plastic strain (see Bases for LCO 3.2.1). References 1 and 2 contain the acceptance limits for the associated DBAs and transients. They are referred to when making modifications to the unit that could affect the reactor steam dome pressure to assess any effect in relation to the acceptance limits. Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Interim Policy Statement.
LCO	The specified reactor steam dome pressure limit of ≤ [1020] psig assures 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.

(continued)

(continued)

BASES (continued)

LCO (continued)

The system is OPERABLE when:

a. All components necessary to provide the function are functional and in service; and

b. All required surveillances are current and have demonstrated acceptable performance.

APPLICABILITY

In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES the reactor may be generating significant steam and the DBAs and transients are bounding. The limit may be exceeded during anticipated operational occurrences; however, the evaluations of References 1 and 2 demonstrate that appropriate reactor and fuel limits are not exceeded.

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-hour 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 placed in MODE 3 to be within the assumptions of the transient analyses.

Reactor steam dome pressure is considered out of limits if the equipment used to measure reactor steam dome pressure is determined to be inoperable. Required Action A.1 applies to restoring such equipment to OPERABLE status.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1

The plant must be placed in a MODE in which the LCO does not apply if the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours. This Completion Time is reasonable, based on operating experience, to reach the required MODE from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Verification that reactor steam dome pressure is ≤ [1020] 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.

[For this facility, reactor steam dome pressure is measured as follows:]

REFERENCES

1. [Unit Name] FSAR, Section [5.2.2.2.4.], "[Title]."
2. [Unit Name] FSAR, Section [15], "[Accident Analyses]."

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

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 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, all ECCS pumps automatically start, simultaneously align, and 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 while the RCS is still pressurized and, thus, vessel level. If HPCS fails, it is backed up by ADS in combination with LPCI and LPCS. In this event, 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 that is cooled by the Standby Service Water System (SWS). Depending on the

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

location and size of the break, portions of the ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break. Although no credit is taken in the safety analysis for the RCIC System, it performs the same function as HPCS but has limited 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 in any subsystem 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 (from normal AC power, if available; otherwise, the pump starts after emergency AC power becomes 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 (from normal AC power, if available; otherwise, the pumps start after emergency AC power becomes 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

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

and to the suppression pool to allow testing of each LPCI pump without injecting water into the RPV.

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. If the CST water supply is low or the suppression pool level is high, however, 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 to 1177 psid, vessel to suction source). Upon receipt of an initiation signal, the HPCS pump automatically starts (from normal AC power, if available; otherwise, the pump starts after emergency AC power becomes 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.

(continued)

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 Reference 5. The required analyses and assumptions are defined in 10 CFR 50 (Ref. 6), and the results of these analyses are described in FSAR, Section 6.3.3 (Ref. 5).

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 7), will be met following a LOCA assuming the worst-case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from zirconium-water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long-term cooling capability is maintained.

The limiting single failures are discussed in Reference 8. For a large-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 satisfies Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

All ECCS subsystems and [eight] ADS valves are required to be OPERABLE. The ECCS subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The low pressure ECCS subsystems are defined as the LPCS System and the three LPCI subsystems.

With fewer 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. 7) could potentially be exceeded. All ECCS subsystems must therefore be properly aligned, tested, maintained, and supported by appropriate support systems to be OPERABLE and to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 7). The ECCS is supported by other systems that provide automatic ECCS initiation signals (LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation"), service water to cool rooms containing ECCS equipment (LCO 3.7.1, "Standby Service Water System (SSW) and Ultimate Heat Sink," and LCO 3.7.2, "High Pressure Core Spray (HPCS) Service Water System"), electrical power (LCO 3.8.1, "AC Sources — Operating," and LCO 3.8.3, "DC Sources — Operating"), suppression pool cooling (Standby SWS), and pneumatic power (ADS instrumentation air supply).

A LPCI subsystem may 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 from the control room to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems can provide the required core cooling, thereby allowing operation of an RHR shutdown cooling loop when necessary.

[For this facility, an OPERABLE HPCS System constitutes the following:]

[For this facility, an OPERABLE LPCI subsystem constitutes the following:]

[For this facility, an OPERABLE LPCS subsystem constitutes the following:]

(continued)

(continued)

BASES (continued)

LCO (continued)

[For this facility, an OPERABLE ADS valve constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure ADS valve OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the ECCS subsystems or ADS valves inoperable and their justification are as follows:]

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, 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.

A Note has been added to provide clarification that all ECCS subsystems and all ADS valves are treated as an entity for this LCO, with a single Completion Time.

ACTIONS

A.1

If any one low-pressure ECCS 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. Overall ECCS reliability is reduced, however, 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. 9) that evaluated the impact on ECCS availability by 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

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

the consequences of a LOCA as a function of allowed outage times (AOTs).

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

With two ECCS subsystems inoperable, at least one ECCS spray subsystem must be immediately verified to be OPERABLE. If HPCS System is one of the inoperable subsystems then RCIC must also be immediately verified to be OPERABLE. At least one subsystem must be restored to OPERABLE status within 72 hours. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC System OPERABILITY is therefore required when HPCS is inoperable. This may be performed by an administrative check or by examining logs or other information to determine that the RCIC System is OPERABLE. Verification does not require performing the SRs needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be immediately verified, Condition D must be immediately entered.

Overall ECCS reliability is reduced in this condition 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. 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 9.

C.1 and C.2

If the HPCS System is inoperable, and the RCIC System is immediately verified to be OPERABLE, the HPCS System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is assured by the OPERABILITY of the redundant and diverse low-pressure ECCS subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCS is inoperable. This may be performed by an administrative check or by

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

examining logs or other information to determine that the RCIC System is OPERABLE. Verification does not require performing the SRs needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be immediately verified, Condition D must be immediately entered. If a single active component fails concurrent with a 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. 9) and has been found to be acceptable through operating experience.

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply, if the Required Actions and associated Completion Times of Condition A, B, or C are not met. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable based on operating experience related to the time required to reach the required MODES from full power 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 10 contains the results of an analysis that evaluated the effect of one ADS valve out of service. Per this analysis, operation of only [seven] ADS valves will provide the required depressurization. The overall reliability of the ADS is reduced, however, and operation is only allowed for a limited time. The 14-day Completion Time is based on a reliability study (Ref. 9) and has been found to be acceptable through operating experience.

F.1 and F.2

If any one low-pressure ECCS subsystem is inoperable in addition to one inoperable required ADS valve, adequate core cooling is assured by the OPERABILITY of HPCS and the remaining low-pressure ECCS subsystems. The ECCS reliability is further reduced, however. If a single active component failure occurs

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

concurrent with a design basis LOCA, the minimum required ECCS equipment may not be available. Since both a high-pressure (ADS) and low-pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is allowed to restore either the low-pressure ECCS subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 9) and has been found to be acceptable through operating experience.

G.1 and G.2

The plant must be placed in a Condition in which the LCO does not apply, if the Required Actions and associated Completion Times of Condition E or F are not met or if two or more required ADS valves are inoperable. This is done by placing the plant in at least MODE 3 within 12 hours and reducing reactor steam dome pressure to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable based on operating experience related to the time required to reach the required MODE and condition from full power in an orderly manner and without challenging plant systems.

H.1

When multiple ECCS subsystems are inoperable, as stated for 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 31-day Frequency is based on the gradual nature of void buildup in the ECCS piping and the procedural controls governing system operation and operating experience.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 non-accident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31-day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve 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 an LPCI subsystem 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 from the control room to the LPCI mode and not otherwise inoperable. This allows operation in the RHR shutdown cooling mode during MODE 3 if necessary.

SR 3.5.1.3

Verification every 31 days that ADS [air receiver] pressure is ≥ [150] psig assures 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. 11). The

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low-pressure ECCS. This minimum required pressure of [ ] 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. 6). Periodic surveillance is performed (in accordance with the American Society of Mechanical Engineers (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. 7).

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 LOCA. These values may be established during preoperational testing. A 92-day Frequency for these tests is in accordance with the Inservice Testing Program and must not be exceeded.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their designed function. These surveillance tests demonstrate 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 sequences, including automatic pump startup, and actuation of all automatic valves to their required positions. This test also ensures that the HPCS System will automatically restart on a RPV low water level (Level 2) signal received subsequent to a RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool.

(continued)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on 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 test. 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 tests.

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 (logic only) is performed to demonstrate that the ADS logic operates as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components.

The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on 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 a RPV 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, or by a change in the measured steam flow, or by any other method suitable to verify steam flow. Adequate

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Sufficient time is therefore allowed, after the required pressure is achieved, to perform this test once only. Adequate pressure at which this test is to be performed is [100] psig (the pressure recommended by the valve manufacturer). 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. Thus, a Note is included in this SR to indicate that SR 3.0.4 does not apply.

The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on 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. [Unit Name] FSAR, Section [6.3.2.2.3], "[Title]."
2. [Unit Name] FSAR, Section [6.3.2.2.4], "[Title]."
3. [Unit Name] FSAR, Section [6.3.2.2.1], "[Title]."
4. [Unit Name] FSAR, Section [6.3.2.2.2], "[Title]."
5. [Unit Name] FSAR, Section [6.3.3], "[Title]."
6. Title 10, Code of Federal Regulations, Part 50, Appendix K, "ECCS Evaluation Models."
7. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors."
8. [Unit Name] FSAR, Section [6.3.3.3], "[Title]."

(continued)

(continued)

BASES (continued)

REFERENCES (continued)

9. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.

10. [Unit Name] FSAR, Section [6.3.3.7.8], "[Title]."

11. [Unit Name] FSAR, Section [7.3.1.1.1.4.2], "[Title]."

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.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses Section of Bases B 3.5.1 also applies to this Bases section. 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 ECCS subsystem is required, post-LOCA, to maintain the peak cladding temperature below the allowable limit. To preserve the single failure criterion, described in Reference 2, a minimum of two ECCS subsystems are required to be OPERABLE in MODES 4 and 5. Two OPERABLE ECCS subsystems also ensure adequate inventory makeup in the reactor pressure vessel (RPV) in the event of an inadvertent vessel draindown.

The ECCS satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

Two ECCS subsystems are required to be OPERABLE and independent for single failure protection. The ECCS 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 in the shutdown cooling mode of the RHR System in MODE 4 or 5 and considered OPERABLE for the ECCS function, if it can be

(continued)

(continued)

BASES (continued)

LCO (continued)

manually realigned from the control room to the LPCI mode and is not otherwise inoperable. Because of low-pressure and low-temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery. Support systems affecting the OPERABILITY of the ECCS are discussed in the LCO section of Bases B 3.5.1.

[For this facility, an OPERABLE HPCS System constitutes the following:]

[For this facility, an OPERABLE LPCI subsystem constitutes the following:]

[For this facility, an OPERABLE LPCS subsystem constitutes the following:]

[For this facility, those required support systems which, upon their failure, do not require declaring the ECCS subsystems inoperable and their justification are as follows:]

APPLICABILITY

OPERABILITY of the ECCS subsystems is required in MODES 4 and 5 to assure 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 Bases B 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the cavity flooded, 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 uncovery in case of an inadvertent draindown.

The Automatic Depressurization System (ADS) 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.

(continued)

BASES (continued)

ACTIONS

A.1 and B.1

If any one required ECCS subsystem is inoperable, the required inoperable ECCS subsystem must be restored to OPERABLE status in 4 hours. In this condition, the remaining OPERABLE subsystem can provide sufficient RPV flooding capability to recover from an inadvertent vessel draindown. Overall system reliability is reduced, however, 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 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. With the inoperable subsystem not restored to OPERABLE status within the required Completion Time, action must immediately be initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and the subsequent potential for fission-product release. Actions must continue until OPDRVs are suspended.

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

If both of the required ECCS subsystems are inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be 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. If at least one ECCS subsystem is not restored to OPERABLE status within the 1-hour Completion Time, additional actions are required to minimize any potential fission-product release to the environment. This includes initiating immediate action to restore the following to OPERABLE status: secondary containment, one standby gas treatment subsystem, and one secondary containment isolation valve, and associated instrumentation in each associated penetration not isolated. This may be performed by an administrative check or by examining logs or other information to determine if the components are out of service for maintenance or other reasons. Verification does not require performing the SRs needed to demonstrate OPERABILITY of the components. If, however, any required

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

component is inoperable, then it must be restored to OPERABLE status. In this case, SRs may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

The 1-hour Completion Time to restore at least one ECCS subsystem (injection or spray) to OPERABLE status ensures that prompt action is 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 ft 8 inches] 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 subsystems are inoperable unless they are aligned to an OPERABLE CST.

When the suppression pool level is less than [12 ft 8 inches], 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 ≥ [12 ft 8 inches] or the HPCS System is aligned to take suction from the CST and the CST contains ≥ [170,000] gallons of water, equivalent to 18 feet, 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, including alarms, available in the control room to alert the operator to an abnormal suppression pool or CST water level condition.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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.

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 non-accident 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 the shutdown cooling mode.

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 from the control room 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.

(continued)

BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [6.3.3.4], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors."

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 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 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. If the CST water supply is low or the suppression pool level is high, however, an automatic transfer to the suppression pool assures 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 (Ref. 2).

The RCIC System is designed to provide core cooling over a wide range of reactor pressures, [ ] to [ ] psig. Upon receipt of an initiation signal from low RPV water level, 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. The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valves in this line

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)	automatically open to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water-hammer effects, the RCIC System discharge line keep fill system is designed to maintain the pump discharge line filled with water.
APPLICABLE SAFETY ANALYSES	The ability of the RCIC System to provide makeup coolant to the reactor is used to respond to transient events. The RCIC System is not an Engineered Safety Feature (ESF) 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 encouraged by the NRC Interim 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 has sufficient capacity to maintain RPV inventory during an isolation event. [For this facility, an OPERABLE RCIC System constitutes the following:] [For this facility, the following support systems are required to be OPERABLE to ensure RCIC System OPERABILITY:] [For this facility, those required support systems which, upon their failure, do not require declaring the RCIC System inoperable and their justification are as follows:]
APPLICABILITY	The RCIC System is required to be OPERABLE in MODES 1, 2, and 3 with reactor steam dome pressure > 150 psig, since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

MODES 4 and 5, RCIC is not required to be OPERABLE since the ECCS subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and A.2

If the RCIC System is inoperable during MODES 1, 2, or 3 with reactor steam dome pressure > 150 psig, and the HPCS System is immediately 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 immediately verified when the RCIC System is inoperable. This may be performed by an administrative check or by examining logs or other information to determine if the HPCS System is OPERABLE. Verification does not require performing the SRs needed to demonstrate the OPERABILITY of the HPCS System. If the OPERABILITY of HPCS system cannot be immediately 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 ECCS Completion Times are based on the results of a study that evaluated the impact on ECCS availability by 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). AOTs were then chosen to provide comparable levels of ECCS availability throughout the industry (Ref. 3). Because of the similar functions of the HPCS and RCIC, the AOTs determined for the HPCS are also applied to RCIC.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status in the associated Completion Time, or if HPCS System is simultaneously inoperable, the plant must be placed in a condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and reducing reactor steam dome pressure to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the time required to reach the required MODE and condition from full power in an orderly manner and without challenging plant systems.

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 (RCS) upon demand. This will also prevent a water hammer following an initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The 31-day Frequency is based on the gradual nature of void buildup in the RCIC piping and 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 non-accident 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,

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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.

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. Since the required reactor steam dome pressure must be available to perform SR 3.5.3.3 and SR 3.5.3.4, sufficient time is allowed after adequate pressure is achieved to perform these tests once only. Reactor startup is allowed prior to performing the low-pressure test because the reactor pressure is low and the time to satisfactorily perform the test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low-pressure test for ECCS pumps has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Thus, a Note is included in SR 3.5.3.3 to indicate that SR 3.0.4 does not apply.

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 was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on the 18-month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Based on operating experience, the 12 hours allowed to demonstrate that the RCIC pump can deliver the rated flow under high and low pressure is sufficient.

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This surveillance test demonstrates that with a required system initiation signal, actual or simulated, the automatic initiation logic of RCIC will cause 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 test also ensures the RCIC System will automatically restart on a RPV low water level (Level 2) signal received subsequent to a RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool.

The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on 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 test. 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 test.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 33, "Reactor Coolant Makeup."

2. [Unit Name] FSAR, Section [5.4.6.2], "[Title]."

3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the reactor primary system following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material within the requirements of 10 CFR 100.11 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). The primary containment consists of a steel-lined, reinforced concrete vessel that surrounds the reactor primary system and provides an essentially leak-tight barrier against an uncontrolled release of radioactivity to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

To ensure that primary containment is OPERABLE, leakage-test requirements have been set forth by Reference 2. These test requirements provide for periodic verification by tests of the leak-tight integrity of the primary containment and systems and components that penetrate the primary containment. The purpose of the leakage tests is to ensure that leakage through the primary containment and systems and components that penetrate the primary containment shall not exceed the allowable leakage rates specified in the technical specification and used in the safety analyses. Additionally, these periodic tests ensure that proper maintenance and repairs are made during the service life of the plant.

To maintain primary containment OPERABILITY, the drywell bypass leakage must be minimized to prevent over-pressurization of the suppression chamber during the drywell pressurization phase of a loss-of-coolant accident (LOCA). This requires periodic testing of the drywell bypass leakage per LCO 3.6.5.1, "Drywell," and confirmation that the primary-containment-to-drywell vacuum breakers are closed per LCO 3.6.5.5.

(continued)

(continued)

BASES (continued)

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 4 and 5. All leakage-rate requirements and SRs are in conformance with 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that the primary containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate, such that, in conjunction with the other containment systems and ENGINEERED SAFETY FEATURE (ESF) systems, the release of fission-product radioactivity subsequent to a DBA will not result in doses in excess of the values given in the licensing basis.

The DBA that results in a release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE at event initiation 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 3 and 4. 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 and that the site-boundary radiation dose will not exceed the limits of 10 CFR 100 (Ref. 1) even if a nonmechanistic release were to occur.

All leakage-rate requirements and SRs are in conformance with 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions as contained in the Primary Containment Leakage Rate Testing Program. 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 P_a, [11.5] psig (Ref. 3). The maximum allowable leakage rate is based on what is acceptable for nuclear safety considerations per 10 CFR 100 (Ref. 1).

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Reactor size, site location, and meteorology, as well as the possible mechanisms for radioactivity generation and transports, are all considered in specifying the allowable leakage rate for a given containment system. For this unit, L_a = [ ]% per day and P_a = [ ] psig, resulting from the limiting design basis LOCA (Ref. 4).

The acceptance criteria applied to accidental releases of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following the onset of the postulated fission-product release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 (Ref. 1) are a whole-body dose of 25 rem or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis, however, may use some fraction of these limits.

Primary containment satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The requirements stated in this LCO define the performance of the primary containment fission-product barrier. The containment design leakage rate (L_a) is an assumed initial condition. Primary containment OPERABILITY is maintained by limiting leakage to within the acceptance criteria of 10 CFR 50, Appendix J (Ref. 2).

The primary containment LCO requires that primary containment OPERABILITY be maintained. Other containment LCOs support this LCO by ensuring that:

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

(continued)

(continued)

BASES (continued)

LCO (continued)

2. closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except as provided in Reference [ ];

b. All equipment hatches are closed;

c. Primary containment air locks are OPERABLE (see LCO 3.6.1.2, Condition C, Note);

d. The primary containment leakage rates are within their limits as defined in the Primary Containment Leakage Rate Testing Program;

e. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O-rings) is OPERABLE; and

f. 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.

The Required Actions, when other primary containment LCOs are not met, have been specified in these LCOs and not in LCO 3.6.1.1.

Compliance with LCO 3.6.1.1 will ensure a primary containment configuration that is structurally sound and will limit leakage to those leakage rates assumed in the safety analysis. As a result, offsite radiation exposures will be maintained within the limits of 10 CFR 100 (Ref. 1) (or the NRC staff-approved licensing basis) following the most limiting DBA. The provisions of this LCO as delineated in the above definition are implemented as follows:

a. OPERABILITY of primary containment penetrations:

1. The OPERABILITY of valves that are closed or are required to close in response to a containment isolation signal is ensured by compliance with the SRs of LCO 3.6.1.3, "Primary Containment Isolation Valves," and 10 CFR 50, Appendix J

(continued)

(continued)

BASES (continued)

LCO (continued)

(Ref. 2), as defined in the Primary Containment Leakage Rate Testing Program. Some of the valves that must be closed to meet the accident analysis assumptions may be opened on an intermittent basis under administrative controls. These valves are identified in Reference [ ]. The Required Actions or SRs of LCO 3.6.1.3 ensure that the associated primary containment isolation valves (PCIVs) close within the required time limit, that the affected penetration is isolated by closed isolation valves or blind flanges, or that the plant is shut down. In addition, the Type C tests required by SR 3.6.1.1.1 and Appendix J require that these PCIVs meet specified leakage-rate criteria, namely, that the combined leakage rate for all penetrations and valves subject to Types B and C tests shall be less than 0.6 L_a.

2. The status of PCIVs that are required to be closed during accident conditions, and do not close automatically, is verified by SRs 3.6.1.3.1, 3.6.1.3.2, 3.6.1.3.3, and 3.6.1.3.4. The valves that must be closed to meet the accident analysis assumptions may be opened on an intermittent basis under administrative controls.

b. The OPERABILITY of the primary containment equipment hatch is ensured by compliance with the leakage criteria established by 10 CFR 50, Appendix J (Ref. 2).

c. The OPERABILITY of the primary containment air locks, required by LCO 3.6.1.2, "Primary Containment Air Locks," requires that at least one door in each air lock be closed during MODES 1, 2, and 3; that the air lock satisfy the required 10 CFR 50, Appendix J (Ref. 2), leakage-test requirements, as described in the Primary Containment Leakage Rate Testing Program; and that the door interlocks function as required.

(continued)

(continued)

BASES (continued)

LCO (continued)

d. Containment leakage-rate requirements are contained in 10 CFR 50, Appendix J (Ref. 2), and the Primary Containment Leakage Rate Testing Program. These requirements are implemented to ensure that the primary containment as a whole, and each of its penetrations and isolation valves, does not exceed the specified leakage rates.

e. The OPERABILITY of penetration sealing mechanisms is ensured by the successful completion of all the leakage-testing requirements stipulated in 10 CFR 50, Appendix J (Ref. 2).

The measures implemented to meet the above requirements provide assurance that the primary containment will perform its designed safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to 10 CFR 100 (Ref. 1) guidelines, or some fraction established in the NRC staff-approved licensing basis.

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.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if primary containment cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage-rate test requirements of 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions, as described in the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage-rate testing requirements with regard to overall primary containment leakage (Type A leakage tests), leakage from equipment hatch, electrical penetrations, and other penetrations except air locks (Type B leakage tests), and PCIVs, except [20]-inch purge valves (Type C leakage tests). These periodic testing requirements verify that the primary containment leakage rate does not exceed the leakage rate assumed in the safety analyses. Leakage-rate testing of the primary containment purge valves is addressed in LCO 3.6.1.3, "Primary Containment Isolation Valves." Air-lock door seal leakage testing is addressed in LCO 3.6.1.2. The Frequency is required by 10 CFR 50, Appendix J (Ref. 2), and identified in the Primary Containment Leakage Rate Testing Program. 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 assured 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 that ensures that the structural integrity of the primary containment will be maintained in accordance with the provisions of the Primary Containment Tendon Surveillance

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Program. Testing and Frequency are consistent with the recommendations of Regulatory Guide 1.35 (Ref. 6).

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area Low Population Center Distance."

2. Title 10, Code of Federal Regulations, Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

3. [Unit Name] FSAR, Section [ ], "[Containment Systems]."

4. [Unit Name] FSAR, Section [ ], "[Title]."

5. [Unit Name] FSAR, Seciton [ ], "[Title]."

6. Regulatory Guide 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures."

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, in order to maintain primary containment OPERABILITY (Ref. 1). As part of the primary containment, the air lock limits the release of radioactive material to the environs during normal plant operation and through a range of incidents 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. As such, closure of a single door ensures that the primary containment is OPERABLE. Each of the doors has inflatable seals that are maintained above [60] psig by the seal air-flask/pneumatic system, which is maintained at a pressure ≥ [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 feet 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 door interlock mechanism is defeated. During periods when primary containment is not required to be OPERABLE, the door 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.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

The primary containment air locks form part of the primary containment pressure boundary. As such, air-lock integrity and air tightness is essential to limit offsite doses from a DBA. Not maintaining air-lock integrity or air tightness may result in offsite doses in excess of those described in the plant safety analyses. All leakage-rate requirements and SRs conform with 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

Primary containment OPERABILITY, and the limiting of radioactive release to the environment, is a consideration in the evaluation of a number of accident analyses. For example, the loss-of-coolant accident (LOCA) analysis requires a primary containment boundary to ensure that the site-boundary radiation dose will not exceed the limits of 10 CFR 100 or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). As delineated in 10 CFR 100 (Ref. 3), the determination of exclusion areas and low-population zones surrounding a site must consider a fission-product release from the core with offsite release based on the expected demonstrable leakage rate from the primary containment.

The DBA that results in a release of radioactive material within primary containment is a LOCA (Ref. 1). In the analysis of this accident, it is assumed that primary containment is OPERABLE at event initiation, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment was designed with an allowable leakage rate of [0.1]% of containment air weight per day. This leakage rate, L_a, is defined in 10 CFR 50, Appendix J (Ref. 2), as [unit-specific #]: the maximum allowable containment leakage rate at the calculated maximum peak containment pressure (P_a) [unit specific #] following a DBA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The acceptance criteria applied to DBA releases of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following onset

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

of the postulated fission-product radioactivity release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 (Ref. 3) are a whole-body dose of 25 rem, or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use some fraction of these limits.

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

Closure of single door in each air lock is sufficient to support primary containment OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry and exit from primary containment.

The primary containment air locks satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

As part of the primary containment, the air lock's safety function is related to control of offsite radiation exposures resulting from a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

The 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 one time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE.

The closure of a single door in an air lock will maintain primary containment OPERABILITY, since each door is designed

(continued)

(continued)

BASES (continued)

LCO (continued)

to withstand the peak primary containment pressure calculated to occur following a DBA.

This LCO provides assurance that the primary containment air locks will perform their designed safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to 10 CFR 100 limits or some fraction established in the NRC staff-approved licensing basis.

[For this facility, the following support systems are required to be OPERABLE to ensure primary containment air lock OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring primary containment air locks inoperable and their justification are as follows:]

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.

The Required Actions of Condition A, B, or C are modified by a Note 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 for repair. If the inner door is the one that is inoperable, however, then it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. If this is not practicable, however, then it is permissible to enter the air lock through the OPERABLE outer door, which means there is a short time during which the containment boundary is not intact (during access through the outer 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

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

is expected to be open. After each entry and exit the OPERABLE door must be immediately closed.

An additional Note has been included to provide clarification that for this LCO, all primary containment air locks are treated as an entity with a single Completion Time.

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

With one air-lock door inoperable in one or more primary containment air locks, an OPERABLE door must be verified closed, and remain closed 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 Required Actions of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the inoperable door in each affected air lock must be restored to OPERABLE status or the affected air-lock penetration must be isolated by locking closed the OPERABLE air-lock door. One of these two Required Actions must be completed within the 24-hour Completion Time. The 24-hour Completion Time is considered reasonable for restoring the air-lock door to OPERABLE status considering the OPERABLE door of the affected air lock is being maintained closed.

Required Action A.2.2.2 verifies 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 leakage-rate acceptance criteria are defined in SR 3.6.1.2.1. The Completion Time of once per 31 days is based on engineering judgment, and is considered adequate in view of other administrative controls, such as indications of interlock mechanism status, available to the operator that ensure that the OPERABLE air-lock door remains closed.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

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

With an air-lock door interlock mechanism inoperable in one or both primary containment air locks, the Required Actions and associated Completion Times consistent with Condition A are applicable.

Condition B is modified by a Note that allows entry and exit through an air lock that is under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at the time and that the opened door is immediately closed.

C.1 and C.2

With one or more air locks inoperable for reasons other than those described in Condition A or B, one door in the affected primary containment air lock must be verified to be closed. This Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the Required Actions of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

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

The Required Actions of Condition C are modified by a Note that requires the primary containment be declared inoperable should both doors in an air lock fail the air lock door seal test, SR 3.6.1.2.1 and SR 3.6.1.2.4.

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

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, as modified by approved exemptions, and as described in the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage-rate testing requirements with regard to air-lock leakage (Type B leakage tests). The acceptance criteria are described in the unit Leakage Rate Test Program. 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, and is described in the Primary Containment Leakage Rate Testing Program. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

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

SR 3.6.1.2.2

The air-lock door 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. 4), closure of either door will ensure primary containment OPERABILITY. Thus, the door interlock feature ensures that primary containment OPERABILITY is maintained 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 primary containment is entered, this test is only required to be performed prior to entering primary containment, but is not required more frequently than once per 184 days. The 184-day Frequency is based on engineering judgement and is considered adequate in view of other administrative

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

controls, such as indications of interlock mechanism status available to operations personnel.

SR 3.6.1.2.3

The seal air-flask pressure is verified to be at ≥ 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 3.6.1.2.4

A seal pneumatic system test to ensure that pressure does not decay at a rate of > [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 was developed considering it is prudent that many Surveillances only be performed during a plant outage. This is due to the fact that the plant must be in a shutdown condition. Operating experience has shown these components usually pass the SR when performed on 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. [Unit Name] FSAR, Section [ ], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors."

3. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

4. [Unit Name] FSAR, Table [6.2-13], "[Title]."

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 values less than 10 CFR 100.11 (Ref. 1) offsite dose limits that are part of the NRC staff-approved licensing basis. 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 adequate primary containment leak tightness is maintained during and after an accident by minimizing potential leakage paths to the environment. Therefore, the OPERABILITY requirements provide assurance that primary containment leakage rates assumed in the safety analysis will not be exceeded. These isolation devices consist of either passive devices or active (automatic) devices. Locked-closed manual valves, deactivated 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. Closed systems are those systems designed in accordance with GDC 57 (Ref. 2). 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 (and possible loss of primary containment OPERABILITY) or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system inside primary containment (in accordance with the Requirements of 10 CFR 50, Appendix A, GDC 57).

Primary containment isolation occurs upon receipt of a high containment pressure or a low Reactor Coolant System (RCS) pressure signal. The primary containment isolation signal closes automatic PCIVs in fluid penetrations not required for operation of ENGINEERED SAFETY FEATURE (ESF) systems

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

in order to prevent leakage of radioactive material. Upon actuation of safety injection, automatic primary containment valves also isolate systems not required for Containment or RCS heat removal. Other penetrations are isolated by the use of valves in the closed position or blind flanges. As a result, the PCIVs (and blind flanges) help ensure that the primary containment atmosphere will be isolated in the event of a release of radioactive material to containment atmosphere from the RCS following a DBA. OPERABILITY of the PCIVs (and blind flanges) ensures that primary containment OPERABILITY is maintained during accident conditions.

The [6]- and [20]-inch primary containment purge valves (PCPVs) are PCIVs that are qualified for use during all operational conditions. The [6]- and [20]-inch PCPVs 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 or as low as reasonably achievable (ALARA) or air quality considerations to ensure that primary containment leakage rates assumed in the safety analysis will not be exceeded. These valves receive an isolation signal. [For this facility the isolation signal consists of the following:]

APPLICABLE SAFETY ANALYSES

The PCIV LCO was derived from the requirements related to the control of offsite radiation doses resulting from major accidents. As delineated in 10 CFR 100.11 (Ref. 1), the determination of exclusion areas and low-population zones surrounding a proposed site must consider a fission-product release from the core with offsite release based on the expected demonstrable leakage rate from the primary containment. This LCO is intended to ensure that offsite dose limits are not exceeded (actual primary containment leakage rate does not exceed the value assumed in the safety analyses). As part of the primary containment boundary, PCIV and PCPV OPERABILITY are essential to primary containment OPERABILITY. 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 within primary containment are a loss-of-coolant accident

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

(LOCA), a main steam line break (MSLB), and a fuel-handling accident inside primary containment (Refs. 3 and 4). 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 leakage paths to the environment through PCIVs (and PCPVs) are minimized. Of the events analyzed in Reference 3, the MSLB is the most limiting event due to radiological consequences. The closure time of the MSIVs is the most significant variable from a radiological standpoint. The MSIVs are required to close in 3 to 5 seconds; therefore, the 5-second closure time is assumed in the analysis. The offsite dose calculations 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 by the rate of primary containment Leakage.

The acceptance criteria applied to accidental releases of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following onset of the postulated fission-product radioactivity release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 are a whole-body dose of 25 rem or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use a specified fraction of these limits. The worst-case 2-hour dose anticipated at the exclusion-area boundary occurs following the postulated worst-case DBA.

The worst-case DBA is a conservative analysis of the LOCA event for which a significant instantaneous release of fission-product radioactivity from the core is postulated.

The DBA analysis assumes that, within 60 seconds after the accident, isolation of the primary containment is complete

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	and leakage terminated, except for the design leakage rate, 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 plant safety analyses was considered in the original design of the PCPVs. 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. The inboard and outboard isolation valves on each line are provided with diverse power sources [motor-operated and pneumatically operated, spring closed, respectively]. This arrangement was designed to preclude common mode failures from disabling both valves on a purge line. 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 PCPV due to failure in the control circuit associated with each valve. Again, the PCPV design precludes a single failure from compromising primary containment OPERABILITY as long as the system is operated in accordance with the subject LCO. The PCIVs satisfy Criterion 3 of the NRC Interim Policy Statement.
LCO	PCIVs form a part of the primary containment boundary. The PCIV safety function is related to control of offsite radiation exposures resulting from a DBA. This LCO addresses PCIV OPERABILITY, stroke time, and PCPV leakage. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," under Type C testing. The automatic isolation valves are considered OPERABLE when their isolation times are within limits, the valves actuate on an automatic isolation signal, and excess-flow check valves actuate within the required differential pressure range. The PCPVs have additional OPERABILITY requirements.

(continued)

(continued)

BASES (continued)

LCO (continued)

PCPVs with resilient seals must meet additional leakage-rate requirements (SR 3.6.1.3.8). PCPVs that are not qualified to close under accident conditions must be sealed-closed or blocked to prevent full opening to OPERABLE. Also, purge system valves actuate on an automatic isolation signal. The valves covered by this LCO are listed with their associated stroke times in the FSAR (Ref. 4).

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are locked-closed, automatic valves are deactivated and secured in their closed position (including check valves with flow through the valve secured), and blind flanges and closed systems are in place. Closed systems are those systems designed in accordance with GDC 57 (Ref. 2). These passive isolation valves/devices are those listed in Reference 5.

Also, OPERABILITY of the PCIVs requires OPERABILITY of the following support systems:

a. ESF System instrumentation that produces isolation signals, including high primary containment pressure, low RCS pressure, [primary containment radiation—High], and Safety Injection System instrumentation;

b. Emergency electrical power; and

c. Instrument air system for pneumatically operated valves.

This LCO provides assurance that the PCIVs will perform their designed safety functions to mitigate the consequences of accidents that could result in offsite exposure comparable to the Reference 1 limits or some fraction as established in the NRC staff-approved licensing basis.

[For this facility, those required support systems which upon their failure do not require declaring PCIVs inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a PCIV and the justification of whether or not each supported system is declared inoperable are as follows:]

(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 PCPVs 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. These valves are those whose associated instrumentation is required to be OPERABLE per LCO 3.3.6 (this does not include the excess-flow check valves that isolate the associated instrumentation).

The Applicability is modified by a Note allowing normally locked- or sealed-closed PCIVs, except the [ ]-inch PCPVs, to be open intermittently under administrative controls. The PCPV exception applies to PCPVs that are not qualified to close under accident conditions. 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 valid primary containment isolation signal 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, these valves may not be opened under administrative control. The provisions of LCO 3.0.4 apply.

A further Note has been added to provide clarification that for the purpose of this LCO, each penetration flow path is independent and is treated as a separate entity with a separate Completion Time.

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

With one or more PCIVs inoperable, at least one isolation valve must be verified to be OPERABLE in each affected open penetration. This action may be satisfied by examining logs or other information to determine if the valve is out of service for maintenance or other reasons. This Required Action is to be completed within 1 hour in order to provide assurance that a primary containment penetration is not open

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

and causing a loss of primary containment OPERABILITY. The 1-hour Completion Time is consistent with LCO 3.6.1.1, "Primary Containment," and is considered a reasonable length of time to complete the Required Action.

In the event that one or more PCIVs are inoperable, either the inoperable valve must be restored to OPERABLE status or the affected penetration 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 deactivated automatic PCIV, a closed manual valve, a blind flange, or a check valve inside primary containment with flow through the valve secured. For penetrations isolated in accordance with Required Action A.2.2.1, the valve used to isolate the penetration should be the closest available one to primary containment. One of these two Required Actions must be completed within the 4-hour Completion Time. For MSIVs, an 8-hour Completion Time to restore the valve to OPERABLE status is provided. The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of maintaining primary containment integrity during MODES 1, 2, and 3.

[For this facility, the Completion Time of 8 hours for MSIVs is justified as follows:]

For affected penetrations that cannot be restored to OPERABLE status within the applicable Completion Time and have been isolated in accordance with Required Action A.2.2.1 the affected penetrations must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time for this is once per 31 days, for valves outside primary containment, drywell, or steam tunnel, and prior to entering MODE 3 from MODE 4 if not performed more often than once per 92 days for valves inside primary containment, drywell, or steam tunnel. The 31-day Completion Time is based on Inservice Inspection and Testing Program requirements to perform valve testing at least once per

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

92 days. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. For valves inside primary containment, the specified time period of prior to entering MODE 3 from MODE 4, if not performed more often than once per 92 days, is based on engineering judgment and is considered reasonable in view of the inaccessibility of the valves and the existence of other administrative controls that will ensure that valve misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is not applicable to those penetrations with only one PCIV and a closed system inside primary containment (i.e., the containment penetration is isolated in accordance with 10 CFR 50, Appendix A, GDC 57) (Ref. 2). The Required Actions for Condition A assume that two valves in series are used to isolate the primary containment penetration and satisfy single-failure concerns.

Required Action A.1 has been further modified by a Note stating that Required Action A.1 is not applicable to penetrations that have only one isolation valve. Since the Note to Condition A excludes penetrations with only one isolation valve and a closed system, the Note to Required Action A.1 refers to penetrations with a single isolation valve on a system that is open inside primary containment but closed outside primary containment. For these systems, if the single isolation valve is inoperable, the intent is to go directly to Required Action A.2.1. These systems are very small piping lines, such as instrument lines that are closed systems outside of primary containment. The justification for a Completion Time of 4 hours is analogous to that for lines with two isolation valves. This Note applies only to small lines.

B.1, B.2.1, and B.2.2

When one or more PCIVs are inoperable, the inoperable valve(s) must be restored to OPERABLE status or the affected penetration 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.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Isolation barriers that meet this criterion are a closed and deactivated automatic valve, a closed manual valve, or a blind flange. A check valve may not be used to isolate the affected penetration, since GDC 57 does not consider the check valve an acceptable automatic isolation valve. One of these Required Actions must be completed within the 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 maintaining primary containment OPERABILITY during MODES 1, 2, and 3. In the event the affected penetration is isolated in accordance with Required Action B.1.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment OPERABILITY is maintained and 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 control and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is applicable only to those penetrations with only one PCIV and a closed system inside primary containment. This Note is necessary since this Condition is written specifically to address those penetrations isolated in accordance with GDC 57 (Ref. 2). GDC 57 allows lines that enter primary containment and that are not part of the reactor coolant pressure boundary nor connected directly to primary containment atmosphere to be isolated by means of one PCIV.

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

In the event that one or more PCPVs are not within the leakage limits, PCPV leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must use 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 deactivated automatic valve, closed manual valve, or blind flange. One of these Required Actions must be completed within 24 hours. The 24-hour Completion Time is reasonable considering the PCPVs remain closed to preclude a

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

gross breach of primary containment. For PCPVs that are isolated in accordance with Required Action C.2.1, SR 3.6.1.3.8 must be performed at least once per 92 days. This ensures that degradation of the resilient seals is detected and confirms that the leakage rate of the PCPVs does not increase during the time the penetration is isolated. The normal Frequency of SR 3.6.1.3.8 is 184 days and is based on an NRC initiative, Generic Issue B-20, "Containment Leakage Due to Seal Deterioration" (Ref. 6). Since more reliance is being placed on a single valve while in this condition, it is prudent to perform the Surveillance more often. Therefore, a periodic interval of once per 92 days is appropriate.

D.1

With one or more PCIVs inoperable in one or more penetration flow paths, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support PCIVs within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition D.

Required Action D.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of PCIVs have been initiated. This can be accomplished by entering the supported systems LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition D of this LCO.]

[For this facility, the identified supported systems Required Actions are as follows:]

E.1

With one or more PCIVs inoperable in one or more penetration flow paths, AND one or more required support or supported features, or both, inoperable associated with the other redundant penetration flow paths, there is a loss of functional capability, and LCO 3.0.3 must be immediately entered. However, if the support or supported feature LCO,

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

or both, takes into consideration the loss of function situation, then LCO 3.0.3 may not need to be entered.

An example illustrating this situation would be when a support PCIV is declared inoperable and subsequently is isolated in a penetration flow path associated with a supported ESF system, then the other penetration flow paths associated with the redundant counterpart supported ESF systems and their support systems must be OPERABLE, otherwise a loss of functional capability exists. A loss of functional capability in this case may place the operation of the plant outside the safety analysis. Therefore, immediate actions must be taken to bring the plant to a MODE outside the Applicability of the LCO for the PCIVs.

F.1 and F.2

The plant must be placed in a MODE in which the LCO does not apply if the Required Actions and associated Completion Times are not met in MODES 1, 2, or 3. This is done by placing the plant in at least MODE 3 within 12 hours and at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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

The plant must be placed in a condition in which the LCO does not apply, if the Required Actions and associated Completion Times are not met. If applicable, CORE ALTERATIONS and handling of irradiated fuel 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—shutdown cooling isolation valves, the actions of LCO [ ] will govern the operation of these valves and alternate solutions to compensate for loss of shutdown cooling, if needed. [For

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

this facility the valves or systems required to be OPERABLE as related to Conditions G, H, and I, and associated with actuation instrumentation required to be OPERABLE per LCO 3.3.6.1 are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

Each [ ]-inch PCPV is required to be verified sealed-closed at 31-day intervals. This SR is intended to apply to PCPVs which 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 PCPV. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to prevent offsite dose limits from exceeding 10 CFR 100 limits (Ref. 1) or some fraction, as established in the NRC staff-approved basis. Therefore, these valves are required to be in sealed-closed position during MODES 1, 2, and 3. PCPVs 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 Item B-24, related to PCPV use during plant operations (Ref. 7).

SR 3.6.1.3.2

This SR ensures that the [6]- and [20]-inch PCPVs are closed as required or, if open, open for an allowable reason. This SR has been modified by a Note indicating that these valves may be opened for inerting, de-inerting, pressure control, ALARA and air quality considerations for personnel entry, and for Surveillance tests that require the valve to be open. These PCPVs 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 PCPV requirements discussed under SR 3.6.1.3.1.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.3

This SR verifies that all primary containment isolation manual valves and blind flanges that are located outside the primary containment, drywell, or steam tunnel and are required to be closed during accident conditions are 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. The Inservice Inspection and Testing Program requires valve testing on a 92-day Frequency. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside primary containment and capable of potentially being mispositioned are in the correct position. Since verification of valve position for valves outside primary containment is relatively easy, the 31-day Frequency was chosen to provide added assurance that the valves are in the correct positions.

Several Notes have been added to this SR. The first Note applies to valves and blind flanges located in high-radiation areas, and allows these valves to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small. A second Note has been added that allows normally locked- or sealed-closed isolation valves to be opened intermittently under administrative controls. These administrative 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 valid primary containment isolation signal is indicated. A third Note has been included to clarify that valves open under administrative controls are not required to meet the SR during the time the valves are open. The provisions of LCO 3.0.4 apply.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.4

This SR verifies that all primary containment isolation manual valves and blind flanges located inside primary containment and required to be closed during accident condition are 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 valves inside primary containment, the Frequency of prior to entering MODE 3 from MODE 4, if not performed more often than once per 92 days, is appropriate since these valves and flanges are operated under administrative control and the probability of their misalignment is low.

A Note has been added to this SR that allows normally locked- or sealed-closed isolation valves to be opened intermittently under administrative controls. The administrative 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 valid primary containment isolation signal is indicated. An additional Note has been included to clarify that valves that are open under administrative controls are not required to meet the SR during the time they are open. The provisions of LCO 3.0.4 apply.

SR 3.6.1.3.5

Demonstrating the isolation time of each power-operated and automatic PCIV is within limits is required to demonstrate OPERABILITY. The isolation-time test ensures that 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 Inspection and Testing Program, but the Frequency should not exceed 92 days. This SR has been modified by a Note indicating that MSIVs may be excluded from this SR since MSIV full-closure isolation time is demonstrated by SR 3.6.1.3.6.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.6

Demonstrating 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. This ensures that the calculated radiological consequences of these events remain within 10 CFR 100 limits. The Frequency of this SR is in accordance with the Inservice Inspection and Testing Program, but must not exceed 92 days.

SR 3.6.1.3.7

The check valves that serve a primary containment isolation function are weight- or spring-loaded to provide positive closure in the direction of flow. This ensures that these check valves will remain closed. This SR verifies the operation of the check valves that are testable during plant operation. The Frequency of 92 days is consistent with the Inservice Inspection and Testing Program requirement for valve testing on a 92-day Frequency.

SR 3.6.1.3.8

For PCPVs with resilient seals, additional leakage-rate testing beyond the test requirements of 10 CFR 50, Appendix J (Ref. 8), is required to ensure OPERABILITY. [For this facility the individual purge valve leakage-rate limits are as follows:] 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 as part of the NRC resolution of Generic Issue B-20, "Containment Leakage Due to Seal Deterioration," (Ref. 6).

Additionally, this SR must be performed within 92 days of opening the valve. The 92-day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that occurring to a valve that has not been opened). Thus, a decrease in the interval (from 184 days) is a prudent measure after a valve

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

has been opened. A Note 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 PCPV leakage is properly accounted for in determining the overall primary containment leakage rate to verify primary containment OPERABILITY.

SR 3.6.1.3.9

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 18-month Frequency was developed considering it is prudent that this Surveillance be performed only during a plant outage, since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. Operating experience has shown that these components usually pass this SR when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.10

The check valves that serve a primary containment isolation function are weight- or spring-loaded to provide positive closure in the direction of flow. This ensures that these check valves will remain closed. This SR verifies the operation of the check valves that are not testable during plant operation. The Frequency of 18 months is based on such factors as the inaccessibility of these valves, the fact that the plant must be shut down to perform the test, and the successful results of the tests on an 18-month basis during past plant operation.

SR 3.6.1.3.11

The analyses in References 4 and 5 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ [100] scfh when tested at P_t [11.5] psig. The MSIV leakage rate must be demonstrated to be in accordance with the leakage-test requirements of 10 CFR 50, Appendix J (Ref. 8), as modified by approved exemptions, as described in the Primary Containment Leakage

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Rate Testing Program. The Frequency of this SR is in accordance with the requirements of the Inservice Inspection and Testing Program.

SR 3.6.1.3.12

Leakage through each hydrostatically tested line that penetrates primary containment is not to exceed 1 gpm when tested at [12.65] psig, 1.1 times P_a. Surveillance of these leakage rates provides assurance that the calculation assumptions of References 4 and 5 are met. Note that dual function valves must pass all applicable SRs including the Type C leakage-rate test (SR 3.6.1.1.1) if appropriate. The combined leakage rates must be demonstrated to be in accordance with the leakage-test requirements of 10 CFR 50, Appendix J, as modified by approved exemptions, as described in the primary containment Leakage Rate Testing Program.

SR 3.6.1.3.13

Demonstrating that each [ ]-inch PCPV is blocked to restrict opening to no more than 50% is required to ensure that the leakage rates assumed in the analyses of References 4 and 5 are met. If the valves were allowed to be fully open, the releases from a DBA LOCA could exceed 10 CFR 100 requirements because the valves could not close against accident pressures. 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 SR when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

(continued)

(continued)

BASES (continued)

REFERENCE (continued)

General Design Criterion 50, "Containment Design Basis;"

General Design Criterion 52, "Capability for Containment Leakages Rate Testing;"

General Design Criterion 53, "Provisions for Containment Inspection and Testing;"

General Design Criterion 54, "Piping Systems Penetrating Containment;"

General Design Criterion 56, "primary containment Isolation;" and

General Design Criterion 57, "Closed System Isolation Valves."

3. [Unit Name] FSAR, Section [ ], "[Title]."
4. [Unit Name] FSAR, Section [ ], "[Title]."
5. [Unit Name] FSAR, Section [ ], "[Title]."
6. Generic Issue (GI) B-20, "Containment Leakage Due to Seal Deterioration."
7. Generic Issue (GI) B-24, "Containment Purge Valve Reliability."
8. Title 10, Code of Federal Regulations, Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Primary Containment Pressure

BASES

BACKGROUND

The primary containment serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA), such that offsite radiation exposures are maintained within the requirements of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). The primary containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a DBA or loss-of-coolant accident (LOCA).

Primary containment pressure is a process variable that is monitored and controlled. The primary containment pressure limits are derived from the input conditions used in the primary containment functional analyses and the primary containment structure external pressure analysis. Should operation occur outside these limits, a loss of primary containment OPERABILITY may result in the event of a DBA. Loss of primary containment OPERABILITY could cause site-boundary doses to exceed values specified in the licensing basis.

The limits on primary-to-secondary containment differential pressure have been developed as 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. 2). Without an appropriate limit on the negative containment pressure, the design limit for negative internal pressure of [-3.0] psid could be exceeded.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

Therefore, the Specification pressure limits of -0.1 psid and +1.0 psid were established (Ref. 3).

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. 4). As a result, primary containment OPERABILITY is ensured.

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

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

LCO

A limitation on the primary-to-secondary containment differential pressure of between -0.1 and 1.0 psid is required to assure 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. As a result, protection of primary containment OPERABILITY is ensured.

[For this facility, the following support systems are required to be OPERABLE to ensure primary containment pressure channel OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the primary

(continued)

(continued)

BASES (continued)

LCO (continued)

containment pressure channel inoperable and their justification are as follows:]

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 MODES 4 or 5 to protect primary containment OPERABILITY.

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 Required Actions of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status in 1 hour.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if primary-to-secondary containment differential pressure cannot be restored to within limits in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

Verifying that primary containment pressure is within limits ensures that operation remains within the limits assumed in

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

the primary containment analysis. The 12-hour Frequency of this SR was developed based on operating experience related to trending primary containment pressure variations and pressure instrument drift during the applicable MODES and to assessing the 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 primary containment pressure condition.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."
2. [Unit Name] FSAR, Section [6.2.1.1.4.2], "[Title]."
3. [Unit Name] FSAR, Section [6.2], "[containment Systems]."
4. [Unit Name] FSAR, Section [6.2.1], "[Title]."

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 plant design remove this energy and maintain an appropriate average temperature inside primary containment. The average airspace temperature affects equipment OPERABILITY, personnel access, and the calculated response to postulated Design Basis Accidents (DBAs). This limit is an initial condition input for the Reference 1 safety analyses. A limit on airspace temperature also ensures that personnel access is not unnecessarily limited during normal plant operation.

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the 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 assures 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). The consequence of 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 and qualified to operate under the expected environmental conditions of the accident. [For this facility, the temperature limit used to establish the environmental qualification operating envelope for primary containment is [ ]°F.]

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

(continued)

BASES (continued)

LCO

With an initial primary containment average temperature less than or equal to the LCO temperature limit, the peak accident temperature can be maintained below the primary containment design temperature during a DBA. As a result, the ability of primary containment to perform its design function is ensured.

[For this facility, the following support systems are required to be OPERABLE to ensure primary containment air temperature OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the primary containment air temperature inoperable and their justification are as follows:]

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 MODES 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 or to prepare the plant for an orderly shutdown.

In the event that the required primary containment air temperatures channels are found inoperable, the primary containment air temperature is considered to be not within limits and Required Action A.1 applies.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1 and B.2

If the primary containment average air temperature cannot be restored within limits in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowable Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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 containment analysis. Primary containment air temperature is monitored in each quadrant and at each elevation. Since the measurements are uniformly distributed, an arithmetic average is an accurate representation of the actual average temperature.

The 24-hour Frequency of the SR was developed considering operating experience related to variations in primary containment average air temperature and temperature instrument drift during the applicable MODES. Furthermore, the 24-hour Frequency is considered adequate in view of other indications, such as alarms available in the control room to alert the operator to an abnormal primary containment air temperature condition.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Low-Low Set (LLS) Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The S/RVs can actuate either in the relief mode, safety mode, the Automatic Depressurization System (ADS) mode, or the LLS relief mode. In the LLS relief mode (or power-actuated mode of operation), a pneumatic diaphragm and stem assembly overcomes the spring force and opens the pilot valve. As in the safety mode, opening the pilot valve allows a pressure differential 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 [50] psig. Below this pressure, steam pressure may not be sufficient to hold the main valve open against the spring force of the pilot valves. 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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

function justifies the primary containment analysis assumption that multiple simultaneous S/RV openings occur only on the initial actuation for DBAs. Even though six LLS S/RVs are specified, all six LLS S/RVs do not operate in any DBA analysis.

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

LCO

Six LLS S/RVs 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 S/RVs to function for controlling the opening/closing of the S/RVs.

[For this facility an OPERABLE LLS S/RV constitutes the following:]

[For this facility the following support systems are OPERABLE to ensure LLS S/RV OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the LLS S/RVs inoperable and their justification are as follows:]

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 S/RVs OPERABLE is not required in MODES 4 or 5.

ACTIONS

A.1

With one of the six LLS S/RVs inoperable, the remaining OPERABLE LLS S/RVs are adequate to perform the designed function. The 14-day Completion Time takes into account the redundant capability afforded by the remaining LLS S/RVs and

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

the low probability of an event in which the remaining LLS S/RV capability would be inadequate.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if more than one LLS S/RV is inoperable, or if the inoperable LLS S/RV cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

A manual actuation of each LLS S/RV 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 or 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. The 18-month Frequency was developed based on the safety and relief valve tests required by the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI (Ref. 3) and the importance of these valves during DBAs. It is also considered prudent that the Surveillance not be performed with the reactor at full power. This is due to the potential for an unplanned plant transient if the SR is performed with the reactor at full power. Operating experience has shown 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.

Since steam pressure is required in order to perform the Surveillance, however, and steam may not be available during a plant outage, the Surveillance should be performed during the shutdown prior to or the startup following a plant outage. Plant startup is allowed prior to performing this

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

test because valve OPERABILITY and the setpoints for overpressure protection are verified by Reference 3 prior to valve installation. After required reactor steam dome pressure is reached, 12 hours are allowed to prepare for and perform the test once only. Adequate pressure at which this test is to be performed is [950] psig (the pressure recommended by the valve manufacturer).

A Note is included in the SR to indicate that the provisions of SR 3.0.4 do not apply.

REFERENCES

1. [Unit Name] [GESSAR-II, Appendix 3BA.8], "[Title]."

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers, New York.

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 System 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 per emergency procedures. [For this facility, RHR Containment spray is initiated automatically by the following signals:]

APPLICABLE SAFETY ANALYSES

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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

[For this facility these results are as follows:]

The equivalent flow path area for bypass leakage has been specified to be [0.9] ft^2 (Ref. 2). The analysis demonstrates that with containment spray operation the primary containment pressure remains within design limits. [For this facility the referenced analyses are outlined as follows:]

The RHR Containment Spray System satisfies Criterion 3 of the NRC Interim 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 (Ref. 2). 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 one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

In addition each RHR containment spray subsystem must satisfy all SRs in order to be considered OPERABLE.

[For this facility the following support systems are required to be OPERABLE to ensure RHR Containment Spray System OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the RHR Containment Spray System inoperable and their justification are as follows:]

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

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

and temperature limitations in these MODES. Therefore, maintaining RHR containment spray subsystems OPERABLE is not required in MODES 4 or 5 to ensure primary containment OPERABILITY.

ACTIONS

A.1

With one RHR containment spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. The 7-day Completion Time was chosen in light of the redundant RHR containment capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

Concurrent failure of two RHR subsystems would result in the loss of functional capability. Therefore, LCO 3.0.3 must immediately be entered.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable RHR containment spray subsystem cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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 they were verified to be in the correct position prior to locking, sealing, or securing. The 31-day Frequency of this SR was developed based upon Inservice Inspection and Testing Program requirements to perform valve

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

testing at least once every 92 days. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside of primary containment and capable of potentially being mispositioned are in the correct position.

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 (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.

<u>SR 3.6.1.7.2</u>

Demonstrating at least every 92 days that each RHR pump develops a flow rate ≥ [5650] gpm while operating in the suppression pool cooling mode with flow through the 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 centrifical pump performance required by Section XI of the American Society for Mechanical Engineers (ASME) Code (Ref. 3). 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 Inspection and Testing Program, but the Frequency must not exceed 92 days.

<u>SR 3.6.1.7.3</u>

This SR demonstrates that each automatic RHR containment spray valve actuates to its correct position on receipt of an actual or simulated actuation signal. Actual spray initiation is not required to meet this SR. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

the potential for an unplanned plant transient if the SR is performed with the reactor at power. 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.

SR 3.6.1.7.4

This surveillance is performed every 5 years to verify that the nozzles are not obstructed and that flow will be provided when required. The 5-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. [Unit Name] FSAR, Section [ ], "[Title]."

2. NUREG-0800, Standard Review Plan 6.2.1.1.c.

3. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers, New York.

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. Instrumentation that controls the operation of the system once it is started is addressed in Specification 3.3.6.5.

APPLICABLE SAFETY ANALYSES

The analyses listed as Reference 1 provide the evaluation of offsite dose consequences during accident conditions. The calculated offsite release rate must meet the requirements of 10 CFR 100 (Ref. 2) or the NRC staff-approved licensing basis (e.g., specified fraction of 10 CFR 100 limits). 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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	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 Interim Policy Statement.
LCO	A minimum of one PVLCS subsystem must be OPERABLE to ensure that total offsite radiological limits of 10 CFR 100, or the NRC staff-approved licensing basis (e.g., specified fraction of 10 CFR 100 limits) are not exceeded. To ensure that these requirements are met, two PVLCS subsystems must be OPERABLE. Therefore, 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 P_a. [For this facility, an operable PVLCS subsystem constitutes the following:] [For this facility, the following support systems are required to be OPERABLE to ensure PVLCS OPERABILITY:] [For this facility, those required support systems which upon their failure do not require declaring the PVLCS inoperable and their justification are as follows:]
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.

(continued)

BASES (continued)

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 that would generate fission products in amounts capable of exceeding the 10 CFR 100 limit or NRC staff-approved licensing basis, the length of time after the event that operator action would be required to prevent exceeding this limit, the low probability of failure of the OPERABLE PVLCS subsystem, and the availability of the PCIVs.

Concurrent failure of two PVLCS subsystems would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable PVLCS subsystems cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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 101.0 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 proper calibration and logic functioning of the instrumentation is performed to satisfy LCO 3.3.6.5, which is required to overlap with this test. 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 SR when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."
2. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

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) to ensure that the limits of 10 CFR 100 (Ref. 2) or the NRC staff-approved licensing basis are not exceeded.

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. Two independent subsystems provide diverse backup to the MSIV isolation function to mitigate potential leakage. (Note that fission products could not be released unless both an inboard and outboard MSIV leaked in conjunction with a steam pipe failure that allowed a release to the environment.) Each subsystem is comprised of blowers (one blower for the inboard subsystem and two blowers for the outboard subsystem), valves, piping, and heaters (for the inboard subsystem only). The four inboard subsystem electric heaters 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 bleed-off. During depressurization, the effluent is discharged to the auxiliary building, which encloses a volume served by the Standby Gas Treatment System (SGTS). The depressurization process reduces the steam line pressure to within the operating capability of equipment used for the bleed-off mode. During bleed-off (long-term leakage control), the leakage flow is diverted to the blower suction and ultimately discharged to the SGTS while at the same time a negative pressure is maintained in the steam lines. This ensures that leakage through the closed MSIVs is collected by the MSIV LCS.

Subsequent to a DBA, system operation starts upon manual actuation. Once system operation is established, it continues to operate unless terminated by control room operators or automatically stopped as dictated by process control.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 1 defines the Design Basis Event and requirements for the MSIV LCS. Reference 1 evaluated plant response without an MSIV LCS for a DBA with an additional seismic-induced failure of non-Category I steam piping, coincident with induced leakage of the MSIVs in excess of the allowable limits. This leakage, combined with site meteorological data, resulted in a calculated dose that exceeded the 10 CFR 100 requirements. The operation of the MSIV LCS prevents a release of untreated leakage for this type of event such that the offsite dose is within 10 CFR 100 requirements or within the NRC staff-approved licensing basis.

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

LCO

Two independent and manually initiated MSIV LCS subsystems must be OPERABLE to satisfy the single-failure criterion as delineated in Reference 1 and to ensure that total site radiological limits are not exceeded. A typical description of the requirement for MSIV LCS OPERABILITY is provided in the Background section.

[For this facility an OPERABLE MSIV LCS constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure MSIV LCS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the MSIV LCS inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause primary containment isolation. 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 MODES 4 or 5 to ensure that primary containment is leak tight.

(continued)

BASES (continued)

ACTIONS

A.1

With one MSIV LCS subsystem inoperable, the inoperable MSIV LCS must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on the redundant capability afforded by the remaining OPERABLE MSIV LCS subsystem and the low probability of the event specified in Reference 1.

Concurrent failure of two MSIV LCS would result in the loss of functional capability. Therefore LCO 3.0.3 must be immediately entered.

B.1 and B.2

The plant must be placed in MODE in which the LCO does not apply if the MSIV LCS subsystems cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1

Each MSIV LCS blower is operated for at least 15 minutes to demonstrate 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 heater is demonstrated by a resistance check, by verifying the temperature rise rate meets specifications, or by verifying that 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 SR when performed at this Frequency.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 demonstrate electrical continuity in SR 3.6.1.9.2). The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. For this facility, the 18-month Frequency has been shown to be acceptable through operating experience and is further justified because other Surveillances performed at shorter Frequencies convey the proper functional status of each MSIV LCS subsystem.

REFERENCES

1. Regulatory Guide 1.96, "Design of Main Steam Line Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants," Revision 1, June 1976.

2. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

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 (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 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 effect 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 below [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 assures that CO loads do not exceed the Mark III CO load definition; and

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)	d. Chugging Loads—a maximum allowable initial temperature of [100]°F assures that expected LOCA temperatures are within the range of Mark III tested conditions.

APPLICABLE SAFETY ANALYSES

The postulated DBA in which the primary containment performance is evaluated against is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the pool temperature analyses required by Reference 3). An initial pool temperature of [95]°F is assumed for the Reference 2 and Reference 1 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 not assumed to initiate during plant testing.

The suppression pool is also designed to quench the energy from S/RV discharges. Thus, the safety analyses related to the suppression pool must consider all accident scenarios that involve S/RV actuations. The limit for the suppression pool average temperature is set low enough to preclude local boiling due to S/RV discharge from the [plant-specific S/RV discharge pressure suppression device].

The suppression pool average temperature limit is also set low enough to preclude pump cavitation by plant water systems that use the suppression pool as a source of water.

Suppression pool average temperature satisfies Criteria 2 and 3 of the NRC Interim 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

(continued)

(continued)

BASES (continued)

LCO (continued)

during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are as follows:

a. Average temperature ≤ 95]°F with THERMAL POWER ≥ 1% RATED THERMAL POWER (RTP) and when not testing equipment that discharges steam to the suppression pool. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature ≤ [105]°F with THERMAL POWER ≥ 1% RTP and when testing equipment that discharges steam to the suppression pool. This requirement ensures that the plant has testing flexibility and was selected to provide margin below the [110]°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ [95]°F in 24 hours per Required Action A.2. Therefore, the time period with temperature above [95]°F is short enough not to cause a significant increase in plant risk.

c. Average temperature ≤ [110]°F with THERMAL POWER ≤ 1% RTP. This requirement ensures that the plant will be shut down upon exceeding [110]°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 intermediate range monitor (IRM) Range 7 has been chosen as 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.

[For this facility an OPERABLE suppression pool average temperature instrumentation channel is established in LCO [ ], "[Title]," or SR [ ], "[Title]," and constitutes the following:]

[For this facility an OPERABLE IRM is established in LCO [ ], "[Title]," or SR [ ], "[Title]," and constitutes the following:]

[For this facility the support systems are as follows:]

(continued)

BASES (continued)

APPLICABILITY

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

A Note has been added to provide clarification that for this LCO, all suppression pool average temperature conditions are treated as an entity with a single Completion Time.

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 above [95]°F, increased monitoring of the pool temperature is required to ensure it remains at or below [110]°F. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly except when testing that adds heat to the 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

The plant must be placed in a MODE in which the LCO does not apply if suppression pool average temperature cannot be restored to within limits in the associated Completion Time. This is done by reducing THERMAL POWER to below 1% RTP in

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

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, C.2, and C.3

Suppression pool average temperature ≤ [105]°F during testing that adds heat to the suppression pool is allowed by the LCO above 1% RTP. If temperature exceeds [105]°F, the testing must be immediately suspended to preserve the pool's heat-absorption capability. The basis for the Completion Times to verify pool temperature is ≤ [110]°F and to restore it to ≤ [95]°F is the same as that provided for Required Action A.1 and A.2 above.

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if suppression pool average temperature cannot be restored to within limits in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

E.1 and E.2

Suppression pool average temperature ≥ [110]°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor MODE switch in the shutdown position. Additionally, when pool temperature is above [110]°F, increased monitoring of pool temperature is required to ensure that it remains below [120]°F. The once per 30-minute Completion Time is adequate, based on operating experience. 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. In addition, SR 3.6.2.11 verifies suppression pool average temperature is within applicable limits every 5 minutes when tests that add heat to the suppression pool are being performed.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

F.1 and F.2

The plant must be placed in a MODE in which the LCO does not apply if suppression pool average temperature cannot be maintained below [120]°F. This is done by reducing reactor pressure to below [200] psig in 12 hours and placing the plant in MODE 4 in 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner without challenging plant systems.

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

G.1, G.2, and G.3

With one or more of the required suppression pool average temperature channels established in LCO [ ], "[Title]," or in SR [ ], "[Title]" inoperable OR with one or more of the required IRM or THERMAL POWER channels established in LCO [ ], "[Title]" or in SR [ ], "[Title]," inoperable, there is no confidence in the comparisons within the limits nor in the adequacy of the pool temperature with respect to RTP (respectively). Therefore, all testing that adds heat to the suppression pool must be immediately suspended, and either all required channels are restored to OPERABLE status within 8 hours or the plant is placed in MODE 4 within 44 hours. The Completion Time of 8 hours take into consideration reasonable time for repairs and the low probability of an event (after all testing has been suspended) that will add heat to the suppression pool occurring during this interval. An additional 8 hours has been added to the normal Completion Time of 36 hours to reach MODE 4 in order to ensure that in the event the channels cannot be restored to OPERABLE status within 8 hours there is sufficient time remaining to reduce power from full power in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

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. At least one suppression pool water temperature instrumentation channel in each sector of the suppression pool must be OPERABLE. The required number of OPERABLE channels is established in LCO [ ] or SR [ ]. The 24-hour Frequency has been shown to be acceptable through operating experience. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5-minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable through 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. [Unit Name] FSAR, Section [ ], "[Containment Systems]."

2. [Unit Name] FSAR, Section [ ], "[Accident Analysis]."

3. NUREG-0783, "Suppression Pool Temperature Limits for BWR Containments," November 1981.

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 System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between [135,291] ft^3, at the low water level alarm of [18'4 1/2"] and [138,701] ft^3 at the high water level alarm of [18'9 3/4"].

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. 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)

(continued)

BASES (continued)

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 Interim Policy Statement.

LCO

A limit that suppression pool water level be from [18'4 1/2"] to [18'9 3/4"] is required to assure 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.

[For this facility, an OPERABLE suppression pool water level constitutes the following:]

[For this facility, that following support systems are required to be OPERABLE to ensure suppression pool water level OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring suppression pool water level inoperable and their justification are as follows:]

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. Therefore, maintaining suppression pool water level within limits is not required in MODES 4 or 5 to ensure primary containment OPERABILITY.

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

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

quenchers are covered. If 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 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 take into account the low probability of an event impacting the suppression pool water level occurring during this interval.

In the event that the required suppression pool water level channels are found inoperable, the suppression pool water level is considered to be not within limits and Required Action A.1 applies.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if suppression pool water level cannot be restored to within limits in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling System

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 turbine trip or a stuck-open safety/relief valve (S/RV). S/RV leakage and Reactor Core Isolation Cooling (RCIC) 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)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

time history for suppression pool temperature is calculated to demonstrate that the maximum temperature remains below the design limit.

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

LCO

During a DBA, 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. A RHR suppression pool cooling subsystem is OPERABLE when one of the pumps, two heat exchangers, and associated piping, valves, instrumentation, and controls are OPERABLE.

In addition each RHR suppression pool cooling subsystem must satisfy all the performance and physical arrangement SRs in order to be considered OPERABLE.

[For this facility the following support systems are required to be OPERABLE to ensure RHR suppression pool cooling subsystem OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the [RHR Suppression Pool Cooling System] inoperable and their justification are as follows:]

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 MODES 4 or 5.

(continued)

BASES (continued)

ACTIONS

A.1

With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. The 7-day Completion Time was chosen in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

Concurrent failure of two RHR suppression pool cooling subsystems would result in the loss of functional capability. Therefore LCO 3.0.3 must be immediately entered.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable RHR suppression pool cooling subsystems cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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, excluding check values, 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 they were verified to be in the correct position prior to being secured. A valve is also allowed to be in the non-accident position provided it can be aligned to its accident condition. This is acceptable since the RHR suppression pool cooling mode is manually initiated. The 31-day frequency of this SR was developed based on the Inservice Inspection and Testing Program requirements to perform valve testing at least once

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

per 92 days. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside primary containment and capable of potentially being mispositioned are in the correct position.

SR 3.6.2.3.2

Demonstrating each RHR pump develops a flow rate > [7450] gpm while operating in the suppression pool cooling mode with flow through the 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 Section XI of the American Society of Mechanical Engineers (ASME) Code (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 Inspection and Testing Program, but the Frequency must not exceed 92 days.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers, New York.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Suppression Pool Makeup System (SPMS)

BASES

BACKGROUND

The function of the SPMS 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 SPMS ensures a post-LOCA suppression pool vent coverage of at least 2 feet 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 SPMS 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;

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)	.. 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 d. Allowances for primary containment spray holdup on equipment and structural surfaces. The SPMS 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 out to at least 30 minutes. Although the minimum freeboard distance above the suppression pool high water level LCO 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 makeup system mode switch may be keylocked in the "OFF" position to assure that inadvertent dump will not occur. Inadvertent actuation of the SPMS 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 SPMS, are contained in References 1 and 2. During these events, the SPMS 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 stays within design limits. The analysis assumes a SPMS dump volume of [36,380] ft^3 at a temperature of [120]°F. (continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	The SPMS satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	During a DBA, a minimum of one SPMS subsystem is required to maintain peak suppression pool temperature below the design limits (Ref. 1). To ensure that these requirements are met, two SPMS 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 SPMS is OPERABLE when the upper containment pool temperature is ≤ [120°]F, the water level is ≥ [23'3"] which corresponds to a SPMS available dump volume of ≥ [36,380] ft^3, gates are in the stored condition, the gravity feed lines are intact, and the system valves are OPERABLE. [For this facility, the following support systems are required to be OPERABLE to ensure SPMS OPERABILITY:] [For this facility, those required support systems which upon their failure do not require declaring the SPMS inoperable and their justification are as follows:]
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 SPMS OPERABLE is not required in MODES 4 or 5 to ensure primary containment OPERABILITY.
ACTIONS	A.1 When upper containment pool water level is < [23'3"], 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

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

pool and maintaining water coverage over the uppermost drywell vents. Loss of water volume has a relatively big impact on heat-sink capability. Therefore, the upper containment pool water level must be restored to within limits within 4 hours. The 4-hour Completion Time is sufficient to provide makeup water to the upper containment pool to restore level within specified limits. Also, it takes into account the low probability of an event impacting the upper containment pool water level.

A Note is added to provide clarification that for this LCO, Conditions A, B, and C are treated as an entity with a single Completion Time.

B.1

When upper containment pool temperature is > [120]°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 level must be restored to within limits within 24 hours. The 24-hour Completion Time is sufficient to restore the upper containment pool to within the specified temperature limits. It also takes into account the low probability of an event occurring that would require SPMS.

C.1

With one SPMS 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 was chosen in light of the redundant SPMS capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

Concurrent failure of two SPMS subsystems would result in the loss of functional capability; therefore, LCO 3.0.3 must be immediately entered.

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the Required Actions and associated Completion

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Times are not met. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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 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 upper containment pool water level condition.

SR 3.6.2.4.2

The upper containment pool temperature is regularly monitored to ensure that the required limits are satisfied. The 24-hour Frequency was developed considering the operating experience related to upper containment pool temperature variations during the applicable MODES and to assessing the proximity to the specified LCO temperature limits.

SR 3.6.2.4.3

Verifying the correct alignment for manual, power-operated, and automatic valves in the SPMS 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 they were verified to be in the correct position prior to being secured. The 31-day Frequency of this SR was developed based on the requirements of the Inservice Inspection and Testing Program to perform valve testing at least once per 92 days. This SR does not require any testing or valve

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

manipulation. Rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

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/maintenance during refueling operations and two additional gates in the separator pool weir wall extension which, when installed, limit personnel exposure and ensure adequate water submergence of the separator when the separator is stored in the pool. The SPMS dump line penetrations are located in the steam separator storage section of the pool. To provide the required SPMS 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.

If upper containment pool gates are found not to be in the stored position, both SPMS subsystems must be declared inoperable.

SR 3.6.2.4.5

This SR requires a demonstration that each SPMS automatic valve actuates to its correct position on receipt of an actual or simulated actuation signal. This includes verification of the correct automatic positioning of the valves and of the operation of each interlock and timer. The 18-month Frequency was developed considering it is prudent that many surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. 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.

REFERENCES

1. [Unit Name] FSAR, Section [6.2], "[Containment Systems]."

2. [Unit Name] FSAR, Section [15], "[Accident Analysis]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiner System (PCHRS)—MODES 1 & 2

BASES

BACKGROUND

The PCHRS supports primary containment OPERABILITY in post-accident environments by eliminating the potential breach of primary containment due to a hydrogen-oxygen reaction.

Per 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 PCHRS is required to reduce the hydrogen concentration in the primary containment following a loss-of-coolant accident (LOCA). The PCHRS 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.

Two independent PCHRS subsystems are provided. Each consists of controls located in the control room, a power supply, and a recombiner located in primary containment. The recombiners have no moving parts. Recombination is accomplished by heating a hydrogen-air mixture above [1150]°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 recombiner is capable of maintaining the hydrogen concentration in primary containment below the 4.1 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner 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 Design Basis Accident (DBA) and that the PCHRS be manually activated to prevent the primary containment atmosphere from reaching a bulk hydrogen concentration of 4.1 v/o.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The PCHRS ensures primary containment OPERABILITY by providing the capability of controlling the bulk hydrogen concentration in primary containment at less than the lower flammable concentration of 4.1 v/o, following a DBA. This control would prevent a primary containment-wide hydrogen burn, thus ensuring primary containment OPERABILITY and minimizing challenges to the OPERABILITY of safety-related equipment located in primary containment. 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;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS); or

c. Hydrogen in the RCS at the time of the LOCA, i.e., hydrogen dissolved in the reactor coolant for control of austenitic stainless-steel intergranular stress corrosion cracking.

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 PCHRS is designed such that, with the conservatively calculated hydrogen generation rates discussed above, a single PCHRS subsystem is capable of limiting the peak hydrogen concentration in primary containment to less than 4.1 v/o (Ref. 4).

The PCHRS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two PCHRS subsystems must be OPERABLE with power from two independent safety-related power supplies. This ensures operation of at least one PCHRS subsystem in the event of a worst-case single active failure.

(continued)

(continued)

BASES (continued)

LCO (continued)

[For this facility, an OPERABLE PCHRS subsystem consists of the following:] In addition a PCHRS subsystem is considered OPERABLE when all SRs are met. Operation with at least one PCHRS subsystem ensures that the post-LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

Unavailability of both PCHRS subsystems might lead to hydrogen accumulation to a concentration sufficient (flammability limit exceeded) to react with oxygen following the accident. The reaction could take place fast enough to lead to high temperatures and overpressurization of primary containment and, as a result, breach primary containment or cause primary containment leakage rates above those assumed in the safety analyses. Damage to safety-related equipment located in primary containment could also occur.

[For this facility, the following support systems are required to be OPERABLE to ensure PCHRS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the PCHRS inoperable and their justification are as follows:]

APPLICABILITY

The purpose of requiring OPERABILITY in MODES 1 and 2 for the PCHRS subsystems is to ensure their immediate availability after the safety injection and scram actuated on a LOCA initiation. In the post-accident LOCA environment, the two PCHRS subsystems are required to control the hydrogen concentration within primary containment below its flammability limit of 4.1 v/o following a LOCA, assuming a worst-case single failure. This ensures primary containment OPERABILITY and prevents damage to safety-related equipment and instruments located within primary containment.

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 these MODES, the probability of an accident requiring the PCHRS is low. Therefore, the PCHRS is not required in MODE 3.

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

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

ACTIONS

A.1

With one PCHRS subsystem inoperable, the inoperable subsystem PCHRS must be restored to OPERABLE status within 30 days. 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 length of time after the event that operator action would be required to prevent hydrogen accumulation from exceeding this limit, and the low probability of failure of the OPERABLE PCHRS subsystem.

Concurrent failure of two PCHRS subsystems is considered a low probability event. If such a double failure did occur, it would be indicative of poor PCHRS reliability and would result in a loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1

If the inoperable PCHRS subsystem cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 in 12 hours. The 12 hours allotted to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power 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 PCHRS subsystem 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 ≥ [1200]°F in [5] hours or less and that it is maintained

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

between [1150]°F and [1300]°F for at least [4] hours to check the capability of the recombiner to properly function (and that significant heater elements are not burned out). The 18-month Frequency for this SR was developed in consideration of such factors as the following:

a. The incidence of PCHRS failing the SR in the past is low;

b. Even when failure of a PCHRS subsystem has been detected, there has been, in all instances, a backup available either from the other PCHRS subsystem or from a diverse system [Standby Gas Treatment System (SGTS)]; and

c. Since the PCHRS is manually started many hours after a LOCA occurs, there is time available to either restore a PCHRS subsystem to a OPERABLE status or activate an alternative.

SR 3.6.3.1.2

This SR ensures that there are no physical problems that could affect PCHRS 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. The 18-month Frequency for this SR was developed in consideration of factors such as the following:

a. The incidence of PCHRS failing the SR in the past is low;

b. Even when failure of a PCHRS subsystem has been detected, there has been, in all instances, a backup available either from the other PCHRS subsystem or from a diverse system [SGTS]; and

c. Since the PCHRS is manually started many hours after a LOCA occurs, there is time available to either restore a PCHRS subsystem to OPERABLE status or activate an alternative.

(continued)

(continued)

BASES (continued)

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 ≥ [10,000] ohms.

The 18-month Frequency for this SR was developed in consideration of factors such as the following:

a. The incidence of PCHRS failing the SR in the past is low;

b. Even when failure of PCHRS subsystem has been detected, there has been, in all instances, a backup available either from the other PCHRS subsystem or from a diverse system [SGTS]; and

c. Since the PCHRS subsystem is manually started many hours after a LOCA occurs, there is time available to either restore a PCHRS subsystem to OPERABLE status or activate an alternative.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Power Reactors."

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup."

3. Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," U.S. Nuclear, Regulatory Commission.

4. [Unit Name] FSAR, Section [ ], "[Title]."

3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment and Drywell Hydrogen Ignition System (HIS)—MODES 1 & 2

BASES

BACKGROUND

The primary containment and drywell HIS supports containment OPERABILITY in post-accident environments by reducing the potential breach of primary containment due to a hydrogen-oxygen reaction.

The HIS is 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), to reduce the hydrogen concentration in the primary containment following a degraded core accident.

The HIS ensures primary containment OPERABILITY and minimizes challenges to safety equipment located within primary containment by limiting the temperatures and pressures that could be experienced from a hydrogen burn following a degraded core accident. Protection of primary containment OPERABILITY limits leakage of fission-product radioactivity from primary containment to the environment. Loss of primary containment OPERABILITY could cause site-boundary doses to exceed values given in 10 CFR 100 (Ref. 3) or the NRC staff-approved licensing basis (e.g., specified fraction of 10 CFR 100 limits).

As a result of NRC rulemaking following the Three Mile Island accident, 10 CFR 50.44 (Ref. 1) was amended to require boiling water reactor plants with Mark III containments to install suitable hydrogen control systems that would accommodate an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water, without loss of primary containment OPERABILITY. The HIS provides this required capability. This requirement was placed on reactor plants 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, if the hydrogen were ignited from a random ignition source,

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

the resulting hydrogen burn would seriously challenge the primary containment OPERABILITY and OPERABILITY of safety systems in primary containment.

The HIS is 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 HIS is arranged in two independent subsystems such that each containment region has two ignitors, one from each subsystem, controlled and powered redundantly so that ignition would occur in each region even if one subsystem failed to energize.

When the HIS is initiated, the ignitors are energized and heat up to a surface temperature ≥ [1700]°F. At this temperature they ignite the hydrogen gas that is present in the airspace in the vicinity of the ignitor. The HIS depends 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 HIS causes hydrogen in containment to burn in a controlled manner as it accumulates following a degraded core accident (Ref. 4). 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 HIS is 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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

the limiting DBA loss-of-coolant accident (LOCA). However, the HIS has 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 plants with Mark III containment. As such, the HIS is considered to be risk significant in accordance with the NRC Interim Policy Statement.

LCO

Each of two HIS subsystems must be OPERABLE with power from an independent safety-related power supply. Typically with one out of two ignitors in one or multiple non-adjacent regions inoperable, both HIS subsystems remain OPERABLE. Typically HIS subsystem OPERABILITY is enhanced by the overlapping of ignitor regions of effectiveness, such that all the ignitors in an HIS subsystem are not required to be OPERABLE for the HIS subsystem to be OPERABLE. [For this facility an OPERABLE HIS subsystem constitutes the following:] [For this facility, OPERABLE hydrogen ignition in the same primary containment and drywell Region constitute the following:]

Operation with at least one HIS subsystem ensures that the hydrogen in primary containment can be burned in a controlled manner. Unavailability of both HIS subsystems could lead to hydrogen buildup to higher concentrations, which could result in a violent reaction if ignited. The reaction could take place fast enough to lead to high temperatures and overpressurization of primary containment and, as a result, breach primary containment or cause primary containment leakage rates above those assumed in the safety analyses. Damage to safety-related equipment located in primary containment could also occur.

[For this facility, the following support systems are required to be OPERABLE to ensure primary containment and drywell HIS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the primary containment and drywell HIS inoperable and their justification are as follows:]

(continued)

BASES (continued)

APPLICABILITY

Requiring OPERABILITY of HIS in MODES 1 and 2 ensures its immediate availability after safety injection and scram actuated on a LOCA initiation. In the post-accident environment, the two HIS subsystems are required to control the hydrogen concentration within primary containment and drywell to near its flammability limit of 4.1 v/o assuming a worst case single failure. This ensures primary containment OPERABILITY and prevents damage to safety related equipment and instruments located within primary containment.

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 these MODES, the probability of an accident requiring the primary containment HIS is low. Therefore, the primary containment HIS 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 HIS is not required to be OPERABLE in MODES 4 and 5 to ensure primary containment OPERABILITY.

ACTIONS

A.1

With one HIS subsystem inoperable, the inoperable 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 degraded core event that would generate hydrogen in amounts equivalent to a metal-water reaction of 75% of the core cladding, the length of time after the event that operator action would be required to prevent hydrogen accumulation from exceeding this limit, the low probability of failure of the OPERABLE HIS subsystem, and the availability of other systems to control hydrogen concentration.

Concurrent failure of two HIS subsystems within a 7-day period is considered to be a low probability event. If such double failure did occur, it would be indicative of poor HIS reliability and would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1 and B.2

With two hydrogen ignitors in one or more primary containment and drywell regions inoperable, verify that there are not both hydrogen ignitors inoperable in two adjacent regions. If it is determined that the protection has been lost in two adjacent regions, then Condition C is entered. Required Action B.2 calls for the restoration of one hydrogen ignitor in each region to OPERABLE status within 7 days. The 7-day Completion Time is based on the same reasons as that given under ACTION A.1.

A Note has been added which allows each containment region to be treated independent of the others with a separate Completion Time.

C.1

If the HI subsystem(s) cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODE from full power 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 confirm that each hydrogen ignitor can be successfully energized. The ignitors are simple resistance heating elements. Therefore, energizing provides assurance of OPERABILITY.

The Frequency of 92 days is based on the Inservice Inspection and Testing Program requirements for determining equipment OPERABILITY and has been shown to be acceptable through operating experience because of the low failure occurrence.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2.3, SR 3.6.3.2.4, and SR 3.6.3.2.5

These functional tests are performed every 18 months to verify system OPERABILITY. Each glow plug is visually examined to ensure it is clean, and the electrical circuitry is energized. All ignitors (glow plugs), including normally inaccessible ignitors, are visually checked for a glow to verify that they are energized. Additionally, the surface temperature of each glow plug is measured to be ≥ [1700°F] to demonstrate that a temperature sufficient for ignition is achieved. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. 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.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Power Reactors."
2. Title 10, Code of Federal Regulations, Part 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup."
3. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."
4. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.3 Primary Containment Hydrogen Mixing System (HMS)—MODES 1 & 2

BASES

BACKGROUND

The primary containment HMS supports primary containment OPERABILITY in post-accident environments by eliminating the potential breach of primary containment due to a hydrogen-oxygen reaction.

The HMS ensures primary containment OPERABILITY by providing 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. Primary containment OPERABILITY limits leakage of fission-product radioactivity from primary containment to the environment.

The post-accident primary containment HMS is an ENGINEERED SAFETY FEATURE and is designed to withstand a loss-of-coolant accident (LOCA) without loss of function. The system has two independent subsystems consisting of compressors, valves, controls, and piping. Each subsystem is sized to pump [500] cfm. The two subsystems are initiated manually. 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 limiting single active failure.

When the concentration of hydrogen in the drywell approaches 4.1 volume percent (v/o), the drywell mixing compressors are started manually by the control room operator. The drywell mixing 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 mixing continues following the LOCA, hydrogen continues to be produced. Eventually, the 4.1 v/o limit is again approached and the hydrogen recombiners are manually placed in operation.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The primary containment HMS ensures primary containment OPERABILITY by providing the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.1 v/o following a Design Basis Accident (DBA). This control would prevent a primary containment-wide hydrogen burn, thus ensuring primary containment OPERABILITY and minimizing challenges to the OPERABILITY of safety-related equipment located in primary containment. 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;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS); or

c. Hydrogen in the RCS at the time of the LOCA, i.e., hydrogen dissolved in the reactor coolant for the control of austenitic stainless steel intergranular stress corrosion cracking.

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. As such, the primary containment HMS is designed to control an amount of hydrogen generation in primary containment that is considerably in excess of the amount that would be calculated from the limiting DBA LOCA (Ref. 2).

The primary containment HMS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

[Two] primary containment HMS subsystems shall be OPERABLE. This assures operation of at least one primary containment HMS subsystem in the event of a worst-case single active failure. Operation with at least one OPERABLE HMS subsystem

(continued)

(continued)

BASES (continued)

LCO (continued)

provides the capability of controlling the bulk hydrogen concentration in primary containment without exceeding the flammability limit. Unavailability of both subsystems might lead to primary containment-wide hydrogen burns.

[For this facility, an OPERABLE primary containment HMS subsystem consists of the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure primary containment HMS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the primary containment HMS inoperable and their justification are as follows:]

APPLICABILITY

Requiring OPERABILITY in MODES 1 and 2 for the primary containment HMS ensures its immediate availability after the safety injection and scram actuated on a LOCA initiation. In the post-accident LOCA environment, the two primary containment HMS subsystems ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.1 v/o in primary containment, assuming a worst-case single active failure. This ensures primary containment OPERABILITY and prevents damage to safety-related equipment and instrumentation located within primary containment.

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 these MODES, the probability of an accident requiring the primary containment HMS is low. Therefore, the primary containment HMS 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. The primary containment HMS is not required in these MODES to ensure primary containment OPERABILITY.

(continued)

BASES (continued)

ACTIONS

A.1

With one primary containment HMS subsystem inoperable, the inoperable train must be restored to OPERABLE status within 30 days. 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 length of time after the event that operator action would be required to prevent hydrogen accumulation from exceeding this limit.

Concurrent failure of two HMS subsystems within a 30-day period is considered a low probability event. If such a double failure did occur, it would be indicative of poor HMS reliability and would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1

The plant must be placed in a MODE in which the LCO does not apply if an inoperable primary containment HMS subsystem cannot be returned to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 in 12 hours. The allowed Completion Time is based on operating experience to reach the required MODE from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1

Operating each primary containment HMS subsystem for $\geq$ 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 Inspection and Testing Program Surveillance Frequencies, operating experience, the known reliability of the compressor and controls, and the two-train redundancy available.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3.2

Demonstrating that each primary containment HMS subsystem flow rate is ≥[500] cfm ensures that each subsystem is capable of maintaining localized hydrogen concentrations below the flammability limit. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. This is because of the plant conditions needed to perform the SR and the potential for unnecessary plant transients if the SR is performed with the reactor at power. 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.

REFERENCES

1. Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," U.S. Nuclear Regulatory Commission.

2. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The primary containment is designed to maintain its OPERABILITY during and following any postulated loss-of-coolant accident (LOCA). During a postulated LOCA, fission products are released directly to the primary containment. The design basis leakage rate for the primary containment and its penetrations (excluding the main steam lines) is 0.35% per day for the duration of the accident.

The function of the secondary containment is to isolate and contain fission products that escape from primary containment following a Design Basis Accident (DBA), to confine the postulated release of radioactive material within the requirements of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits), 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 plant design basis postulates that a non-isolable release of significant fission products can occur only inside the primary containment. Since the primary containment is a high-pressure leak-tight barrier, the bulk of these fission products is expected to remain entrapped within the primary containment and the primary containment is expected to maintain release rates below those required by 10 CFR 100.

As an extra barrier to accommodate small quantities of fission products that may escape from primary containment, a secondary containment has been provided. Additionally, the secondary containment is the required fission-product barrier for some plant operations that occur outside primary containment (e.g., handling irradiated fuel) or occur when the primary containment need not be OPERABLE.

The secondary containment is a structure with a known leakage rate 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

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

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 System (SGTS)."

APPLICABLE SAFETY ANALYSES

The secondary containment provides a dilution and hold-up volume for fission products that may leak from the primary containment following a postulated accident. In conjunction with operation of the SGTS, the secondary containment is designed to limit the thyroid dose and the whole-body dose resulting from a LOCA to within the guidelines of 10 CFR 100 or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

There are three principal accidents for which credit is taken for secondary containment OPERABILITY. These are a LOCA (Ref. 2), a fuel-handling accident inside primary containment (Ref. 3), and a fuel-handling accident in the fuel building (Ref. 4). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to limit offsite radiation doses to below those required by 10 CFR 100. Maintaining secondary containment OPERABLE ensures that the release of radioactive materials from the primary containment is restricted to those leakage paths and associate leakage rates assumed in the accident analysis and that fission products entrapped within the secondary containment structure will be treated prior to discharge to the environment.

Secondary containment satisfies Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

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

The secondary containment LCO requires that secondary containment OPERABILITY be maintained. [For this facility, other secondary containment LCOs support this LCO by ensuring:]

The Required Actions when other secondary containment LCOs are not met have been specified in those LCOs and not in LCO 3.6.4.1.

[For this facility, an OPERABLE secondary containment constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure secondary containment OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the secondary containment inoperable and their justification are as follows:]

APPLICABILITY

Maintaining secondary containment OPERABILITY prevents leakage of radioactive material from the secondary containment. 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 Reactor Coolant System (RCS) pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODES 4 or 5 to ensure primary containment

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

OPERABILITY, except for other situations for which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during the handling of irradiated fuel assemblies or other loads over irradiated fuel assemblies.

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4-hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If secondary containment cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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

Irradiated fuel handling in the secondary containment, moving loads over irradiated fuel, 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 handling of irradiated fuel or other loads must be immediately suspended if the secondary containment is inoperable.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Suspension of these activities shall not preclude completing an action that involves moving 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. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note that states that LCO 3.0.3 is not applicable. If handling fuel while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent of reactor operations. Therefore, in either case, inability to suspend handling of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. However, the secondary containment in MODES 1, 2, and 3 must be restored to OPERABLE status within the specified time of 4 hours or the plant must be placed in a MODE in which the LCO does not apply, including entering LCO 3.0.3.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

It has been established (Ref. 4) that the secondary containment should be ≥ [0.25] inches of vacuum water gauge under all wind conditions up to the wind speed at which diffusion becomes great enough to ensure site-boundary exposures less than those with a LOCA, even if exfiltration were to occur. In this manner, the inleakage of fresh air negates the tendency of the fission products to exfiltrate through the secondary containment barrier if the secondary containment were inoperable. This SR ensures that secondary containment remains within the specified limit. The 24-hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations and instrument drift during the applicable MODES.

Furthermore, the 12-hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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. Additionally, exterior environmental disturbances (e.g., wind gusts) cannot cause the secondary containment to experience a positive pressure relative to the environment. Verifying that all such openings are closed provides adequate assurance that infiltration or exfiltration from the secondary containment will not occur. Maintaining secondary containment OPERABILITY requires maintaining each door in the access opening closed, except when the access opening is being used for normal transient entry and exit (then at least one door must remain closed). The 31-day Frequency for these SRs is based on engineering judgment, and is considered adequate in view of the other indications of door and [hatch] status that are available to the operator.

SR 3.6.4.1.4

Performance of this surveillance would give advance indication of gross determination of the concrete structural integrity of the secondary containment. The Frequency of this SR is the same as that of SR 3.6.1.1.1. The verification is done during shutdown and as part of Type A leakage tests associated with SR 3.6.1.1.1.

SR 3.6.4.1.5 and SR 3.6.4.1.6

The SGTS exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all untreated fission products are treated, SR 3.6.4.1.5 demonstrates that the SGTS 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 SGTS subsystem will draw down the secondary containment to ≥ [0.25] inches of vacuum water gauge in ≤ [120] seconds. This cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.6 demonstrates that one SGTS subsystem can maintain ≥ [0.25] inches of vacuum water gauge over a 1 hour period at a flow rate of ≤ [4000] cfm. The 1-hour test

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	period allows secondary containment to be in thermal equilibrium at steady-state conditions. Therefore, these two tests are used to ensure secondary containment boundary OPERABILITY. Since these SRs are secondary containment tests, they need not be performed with each SGTS subsystem. The SGTS subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SGTS subsystem will perform this test. While this SR can be performed with the reactor at power, 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.
REFERENCES	1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance." 2. [Unit Name] FSAR, Section [15.6.5], "[Title]." 3. [Unit Name] FSAR, Section [15.7.6], "[Title]." 4. [Unit Name] FSAR, Section [15.7.4], "[Title]."

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) such that offsite radiation exposures are maintained within the requirements of 10 CFR 100 (Ref. 2) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that escape from primary containment following a DBA, or which are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment, are maintained within applicable limits.

The OPERABILITY requirements for SCIVs help ensure that adequate secondary containment leak tightness is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices are either passive or active (automatic). Locked-closed manual valves, deactivated automatic valves secured in their closed position, blind flanges, and closed systems are considered passive devices. Check valves or other automatic valves designed to close without operation 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 (and possibly loss of secondary containment OPERABILITY).

Automatic SCIVs close on a secondary containment isolation signal(s) to prevent leakage of radioactive material from secondary containment following a DBA or other accidents.

[For this facility the secondary containment isolation signals are as follows:]

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)	Other penetrations are isolated by the use of valves in the closed position or blind flanges. OPERABILITY of SCIVs (and blind flanges) ensures that secondary containment OPERABILITY is maintained during accident conditions.
APPLICABLE SAFETY ANALYSES	The SCIVs must be OPERABLE to ensure that secondary containment is a leak-tight barrier to fission-product releases. The principal accidents for which secondary containment leak tightness is required are a loss-of-coolant accident (LOCA) (Ref. 1), a fuel-handling accident inside 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 its leak tightness is required to limit offsite radiation releases to below those levels required by 10 CFR 100, or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated prior to discharge to the environment. SCIVs satisfy Criterion 3 of the NRC Interim 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 (including specific operations when primary containment is not required to be OPERABLE) to within 10 CFR 100 limits. The automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 5.

(continued)

(continued)

BASES (continued)

LCO (continued)

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are locked-closed, automatic valves are deactivated and secured in their closed position, and blind flanges and closed systems are in place. These passive isolation valves or devices are listed in Reference 5.

[For this facility, OPERABILITY of SCIVs requires OPERABILITY of the following support systems:]

[For this facility, those required support systems which upon their failure do not require declaring the SCIVs inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a SCIV and the justification of whether or not each supported system is declared inoperable are as follows:]

This LCO provides assurance that the SCIVs will perform their intended safety functions to mitigate the consequences of accidents that could result in offsite radiation releases that exceed the 10 CFR 100 limits or some fraction of these limits as established by the NRC staff-approved licensing basis.

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.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the Reactor Coolant System pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODES 4 or 5 to back up primary containment OPERABILITY, except for other situations under which significant radioactive releases can be postulated such as during operations with a potential for draining the reactor vessel (OPDRVs), CORE ALTERATIONS, the handling of irradiated assemblies, or when moving loads over irradiated fuel assemblies. Moving irradiated fuel assemblies in the secondary containment or moving loads over irradiated fuel assemblies may also occur in MODES 1, 2, and 3.

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

A Note has been added to provide clarification that each penetration flow path is independent and is treated as a separate entity with a separate Completion Time for the purpose of this LCO.

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

With one or more SCIVs inoperable, at least one isolation valve must be verified to be OPERABLE in each affected open penetration. This action may be satisfied by examining logs or other information to determine whether the valve is out of service for maintenance or other reasons. This Required Action is to be completed within 1 hour in order to provide assurance that a secondary containment penetration is not open and causing a loss of secondary containment OPERABILITY. The 1-hour Completion Time is considered a reasonable length of time needed to complete the Required Action, and it is the same Completion Time used for primary containment isolation valves (PCIVs)in LCO 3.6.1.3.

In the event that one or more SCIVs are inoperable, either the inoperable valve must be restored to OPERABLE status or the affected penetration 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 deactivated automatic SCIV, a closed manual valve, or a blind flange. For penetrations isolated in accordance with Required Action A.2.2.1, the valve used to isolate the penetration should be the closest available valve to secondary containment. One of these two Required Actions must be completed within the 4-hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration, and it is the same Completion Time used for PCIVs in LCO 3.6.1.3.

For affected penetrations that cannot be restored to OPERABLE status within the 4-hour Completion Time and have been isolated in accordance with Required Action A.2.2.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

secondary containment penetrations required to be isolated following an accident, but are no longer capable of being automatically isolated, will be in the isolation position should an event occur. The 31-day Completion Time is based upon Inservice Inspection and Testing Program Requirements to perform valve testing at least once per 92 days. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves capable of potentially being mispositioned are in the correct position.

The Required Actions of Condition A are modified by a Note allowing normally locked- and sealed-closed SCIVs to be opened 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 valid secondary containment isolation signal is indicated. The provisions of LCO 3.0.4 apply.

Required Actions of Condition A are further modified by a second Note stating that Required Action A.1 is not applicable to penetrations that have only one isolation valve. If the single isolation valve is inoperable, the intent is to go directly to Required Action A.2.1.

[For this facility, systems with single isolation valves are as follows:]

The justification for a Completion Time of 4 hours is similar to that for lines with two isolation valves.

[For this facility, the second Note applies only to the following type of lines:]

B.1

With one or more SCIVs inoperable in one or more penetration flow paths, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support SCIVs within the Completion Time of [ ] hours.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition B. Required Action B.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of SCIVs have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition B of this LCO.]

[For this facility, the identified supported systems Required Actions are as follows:]

C.1

With one or more SCIVs inoperable in one or more penetration flow paths AND one or more support or supported features, or both, inoperable associated with the other redundant penetration flow paths, there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the support or supported feature LCO, or both, take into consideration the loss of function, then LCO 3.0.3 may not need to be entered.

An example illustrating the loss of function situation is presented in B 3.6.1.3, "Primary Containment Isolation Valves."

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the Required Actions and associated Completion Times are not met. This is done by placing the plant in at least MODE 3 within 12 hours and at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

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

The plant must be placed in a condition in which the LCO does not apply if the Required Actions and associated Completion Times are not met. If applicable, CORE ALTERATIONS and the handling of irradiated fuel or other loads in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission-product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note which states that LCO 3.0.3 is not applicable. If handling fuel while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent of reactor operations. Therefore, in either case, inability to suspend handling of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. However, SCIVs in MODES 1, 2, and 3 must be restored to OPERABLE status or isolated within the specified time of 4 hours, or the plant must be placed in a MODE in which the LCO does not apply, including entering LCO 3.0.3.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that all manual SCIVs and blind flanges that are required to be closed during accident conditions are 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. The 31-day Frequency of this SR was developed based upon Inservice Inspection and Testing Program requirements to perform valve testing at least once 92 days. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves in secondary containment that are capable of potentially being mispositioned are in the correct position.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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

Several Notes have been added to this SR. The first Note applies to valves and blind flanges located in high-radiation areas and allows these valves to be verified as closed 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 as low as reasonably achievable reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

A second Note has been added that allows normally locked- or sealed-closed isolation valves to be opened under administrative controls. These administrative 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 valid secondary containment isolation signal is indicated.

A third 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. The provisions of LCO 3.0.4 apply.

<u>SR 3.6.4.2.2</u>

Demonstrating that the isolation time of each power-operated and automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the Inservice Inspection and Testing Program, but the Frequency must not exceed 92 days.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.3

In the secondary containment, the check valves that serve a containment isolation function are weight- or spring-loaded to provide positive closure in the direction of flow. This ensures that these check valves will remain closed. SR 3.6.4.2.3 verifies the operation of the check valves that are testable during plant operation. The Frequency of 92 days is consistent with the Inservice Inspection and Testing Program requirement for valve testing on a 92-day Frequency.

SR 3.6.4.2.4

Automatic SCIVs close on a secondary containment isolation signal 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 its isolation position on a secondary containment isolation signal. While this SR can be performed with the reactor at power, 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.

SR 3.6.4.2.5

In the secondary containment, the check valves that serve a containment isolation function are weight- or spring-loaded to provide positive closure in the direction of flow. This ensures that these check valves will remain closed. SR 3.6.4.2.5 verifies the operation of the check valves that are not testable during plant operation. The Frequency of 18 months is based on such factors as the inaccessibility of these valves, the fact that the plant must be shut down to perform the tests, and the successful results of the tests on an 18-month basis during past plant operation.

(continued)

BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [15.6.5], "[Title]."

2. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

3. [Unit Name] FSAR, Section [15.7.6], "[Title]."

4. [Unit Name] FSAR, Section [15.7.4], "[Title]."

5. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment System (SGTS)

BASES

BACKGROUND

The SGTS is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1), 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. This system reduces the potential releases of radioactive material, principally iodine, to within values specified in 10 CFR 100 (Ref. 2) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

The SGTS consists of the following components:

a. Two, 100%-capacity, charcoal filter trains, each consisting of (components listed in order of the direction of the air flow):

   1. a moisture separator,
   2. an electric heater,
   3. a prefilter,
   4. a high efficiency particulate air (HEPA) filter,
   5. a charcoal adsorber,
   6. a second HEPA filter, and
   7. a centrifugal fan with inlet flow control vanes; and

b. Two fully redundant subsystems, each with its own set of ductwork, dampers, and controls.

The sizing of the SGTS equipment and components is based on the results of an infiltration analysis as well as an exfiltration analysis of the secondary containment. The internal pressure of the SGTS boundary region is maintained at a negative pressure of [0.25] inches water gauge (Ref. 3) 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] degrees to the building.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

The moisture separator is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the air stream to less than [70]% (Ref. 4). 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 SGTS 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. SGTS 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 SGTS is to mitigate the consequences of a loss-of-coolant accident and fuel-handling accidents (Ref. 4 and 5). For all events analyzed, the SGTS is shown to be automatically initiated to limit, via filtration and absorption, the site-boundary radioactivity dose level to well within the 10 CFR 100 limits.

The acceptance criteria applied to accidental releases of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following the onset of the postulated fission-product release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 are a whole-body dose of 25 rem or a dose of 300 rem to the thyroid from iodine

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

exposure, or both. The NRC staff-approved licensing basis may use some fraction of these limits.

The SGTS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Following a DBA, a minimum of one SGTS subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. To ensure this requirement is met, two subsystems must be OPERABLE. Thus, meeting the LCO requirements assures operation of at least one SGTS subsystem in the event of a single active failure.

[For this facility, an OPERABLE SGTS constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure SGTS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the SGTS inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of the SGTS and the justification of whether or not each supported system is declared inoperable are as follows:] It should be noted that LCO 3.6.4.3 may need to be augmented with additional Conditions, if it is determined that SGTS provides support to other systems included in the Technical Specifications.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission-product release to primary containment that subsequently enters secondary containment. Therefore, SGTS 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 SGTS OPERABLE is not required in MODE 4 or 5, except for other

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)	situations under which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, when handling irradiated fuel assemblies in the primary or secondary containment, or when moving other loads over irradiated fuel assemblies.

ACTIONS

A.1

With one SGTS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. The 7-day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGTS and the low probability of a DBA occurring during this period.

Concurrent failure of two SGTS subsystems would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply, if the SGTS cannot be restored to OPERABLE status in the associated Completion Time in MODES 1, 2 or 3. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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

During handling of irradiated fuel or moving other loads over irradiated fuel, CORE ALTERATIONS, or OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGTS subsystem should be immediately placed in operation. This 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.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

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

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

When two SGTS subsystems are inoperable, if applicable, CORE ALTERATIONS, handling of irradiated fuel in primary or secondary containment, or moving other loads over irradiated fuel must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission-product release; actions must continue until OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGTS subsystem for ≥ [10] hours, ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ [10] 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 two-train redundancy available.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.3.2

The Ventilation Filter Testing Program (VFTP) (Specification 5.8.4.5) encompasses all the SGTS filter tests consistent with Regulatory Guide 1.52 (Ref. 6). 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. the following tests are included:

a. Verification of the in-place (cold) penetration and bypass dioctyl phthalate (DOP) test leakage of each SGTS train (the cold DOP test confirms the validity of the pre-installation hot DOP test and allows proper filter performance to be inferred);

b. Verification of the in-place penetration and bypass halogenated hydrocarbon refrigerant gas test leakage of each SGTS train (this test determines that no bypass paths exist through or around the charcoal adsorber bed);

c. Verification of the methyl iodide penetration of a charcoal sample from each filter bed (this test verifies that the charcoal adsorption capability is within required limits);

d. Verification that the flow rate of each SGTS train and the pressure drop across the combined prefilters, HEPA filter, and charcoal adsorber banks are within the required limits; and

e. Verification, for systems with heaters, of the proper function of each SGTS train's heaters.

SR 3.6.4.3.3

This SR requires demonstration that each SGTS subsystem starts on receipt of a simulated or actual initiation signal. While this Surveillance can be performed with the [illegible] at power, operating experience has shown these components usually pass the SR when performed on the

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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

SR 3.6.4.3.4

This SR requires demonstration that the cooler bypass damper can be opened and the fan started. This assures that the ventilation mode of SGTS operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the SR when performed on 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. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," GDC 41, "Containment Atmosphere Cleanup."

2. Title 10, Code of Federal Regulations, Part 100.11, "Determination or Exclusion Area, Low Population Zone, and Population Center Distance."

3. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants Branch Technical Position, CSB 6-3, "Determination of Bypass Leakage Paths in Dual Containment Plants."

4. [Unit Name] FSAR, Section [ ], "[Containment Systems]."

5. [Unit Name] FSAR, Section [ ], "[Accident Analysis]."

6. Regulatory Guide 1.52, Rev. 2, "Design, Testing, and Maintenance Criteria for Post Accident Engineered Safety Feature Atmospheric Cleanup System Air Filtration and Absorption Units of Light-Water Cooled Nuclear Power Plants."

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, which have isolation valves at the primary containment boundary. The function of the drywell is to maintain a pressure boundary to separate the RPV and the primary containment and to channel steam from a loss-of-coolant accident (LOCA) to the suppression pool. The drywell also protects accessible areas of the containment from radiation originating in the reactor core and Reactor Coolant System (RCS). The drywell is part of the RCS, which functions to confine the postulated release of radioactive material from a Design Basis Accident (DBA) within the requirements of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

To ensure primary containment OPERABILITY, 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.

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. 2).

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. The associated fission-product release following a DBA forms the basis for determination of offsite doses. The primary containment design basis

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

analyses of Reference 2 are based on the successful condensation of steam in the suppression pool and the primary containment design leakage rate.

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

LCO

Maintaining the drywell OPERABLE is required to assure that the pressure-suppression design functions and the drywell leakage rate assumed in the safety analyses are met. The drywell is OPERABLE if the bypass leakage is within limits and the drywell structural integrity is intact.

The drywell LCO requires that drywell OPERABILITY be maintained. Other drywell LCOs support this LCO by ensuring that:

a. The drywell air lock is OPERABLE (LCO 3.6.5.2);

b. The drywell penetrations required to be closed during accident conditions are either (LCO 3.6.5.3):

   1. capable of being closed by an OPERABLE automatic DIV, or

   2. closed by manual valves, blind flanges, or deactivated automatic valves secured in closed positions;

c. The drywell air temperature and differential pressure are within limits (LCOs 3.6.5.4 and 3.6.5.5); and

d. The Drywell Vacuum Relief System is OPERABLE.

The Required Actions when other drywell LCOs are not met have been specified in those LCOs and not in LCO 3.6.5.1.

In addition, the drywell is maintained OPERABLE by meeting SRs 3.6.1.1.1 and 3.6.1.1.2.

[For this facility, the following support systems are required to be OPERABLE to ensure drywell OPERABILITY:]

(continued)

(continued)

BASES (continued)

LCO (continued)	[For this facility, those required support systems which upon their failure do not require declaring the drywell inoperable and their justification are as follows:]
APPLICABILITY	In MODES 1, 2 and 3, a DBA could cause a release of radioactive material to the drywell. 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 to prevent leakage of radioactive material from primary containment.
ACTIONS	<u>A.1</u> 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. <u>B.1 and B.2</u> The plant must be placed in a MODE in which the LCO does not apply if the drywell cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1.1

The analyses in Reference 2 are based on a maximum drywell bypass leakage. This Surveillance assures that the actual drywell bypass leakage is well below (< [10]%) that assumed in the licensing 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 might occur. 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.

SR 3.6.5.1.2

The 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. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

2. [Unit Name] FSAR, Section [6], "[Title]," and Section [15], "[Title]."

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 MODE 3 and MODE 2 during low-power phase of plant 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 plant operation, the drywell air lock is kept sealed. The air pressure in the seals is maintained above [60] psig by the seal air-flask/pneumatic system, which is maintained at a pressure > [90] psig.

The 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 post-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] feet 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 door 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 door interlock mechanism is defeated.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

The drywell air lock forms part of the drywell pressure boundary. As such, air-lock integrity is essential to limit offsite doses from a Design Basis Accident (DBA). Not maintaining air-lock integrity may result in offsite doses in excess of those described in the plant safety analyses. All leakage-rate requirements and SRs are in conformance with 10 CFR 50, Appendix J (Ref. 1), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

Drywell OPERABILITY, and the limiting of radioactive release to the environs, is a consideration in the evaluation of a number of accident analyses (Ref. 2). For example, the safety analyses assumes 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 containment boundary, its design and maintenance are essential to maintaining drywell OPERABLE, which assures that the safety analyses are met. Drywell air-lock OPERABILITY is also required to minimize the amount of fission-product gases that may bypass the drywell and contaminate and pressurize the primary containment. The drywell air lock must meet the leakage limits of the SRs to ensure that the primary containment leakage rate will be within the limits assumed in the safety analyses. The acceptance criteria applied to accidental releases of fission-product radioactivity to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following onset of the postulated fission-product radioactivity release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 (Ref. 3) are a whole-body dose of 25 rem, or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use some fraction of these limits.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Closure of a single door in the air lock is sufficient to support drywell OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for entry and exit from the drywell.

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

LCO

The drywell air lock forms part of the drywell pressure boundary. As part of drywell OPERABILITY, the air-lock safety function is related to ensuring 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. The closure of a single door in an air lock will maintain drywell OPERABILITY, since each door is designed to withstand the peak drywell pressure calculated to occur following a DBA.

This LCO provides assurance that the drywell air lock will perform its designed safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to 10 CFR 100 limits, or some fraction established in an NRC staff-approved licensing basis.

[For this facility, the following support systems are required to be OPERABLE to ensure drywell air-lock OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring drywell air locks inoperable and their justification are as follows:]

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the drywell. 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 to prevent leakage of radioactive material from drywell.

The Required Actions for Conditions A, B, and C are modified by a Note 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.

An additional Note has been included to provide clarification that for this LCO, the drywell air lock is treated as an entity with a single Completion Time.

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

With one air-lock door inoperable, the OPERABLE door must be verified closed and remain closed. This assures 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 Required Actions of LCO 3.6.5.1, "Drywell," which requires that the drywell be restored to OPERABLE status within 1 hour.

In addition, the inoperable door in the air lock must be restored to OPERABLE status or the air-lock penetration must be isolated by locking closed the OPERABLE air-lock door. One of these two Required Actions must be completed within the 24-hour Completion Time. The Completion Time is considered reasonable for restoring the air-lock door to

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

OPERABLE status, considering that the OPERABLE door is being maintained closed.

Required Action A.2.2.2 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 since other administrative controls, such as indications of interlock mechanism status available to the operator, ensure that the OPERABLE air-lock door remains closed.

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

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

Condition B is modified by a Note that allows entry and exit through an air lock under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time and that the opened door is immediately closed.

C.1 and C.2

With the air lock inoperable for reasons other than those described in Condition A or B, one door in the drywell air lock must be verified to be closed. This action must be completed within the 1-hour Completion Time. This specified time period is consistent with the Required Actions of LCO 3.6.5.1, "Drywell," 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.

The Required Actions of Condition C are modified by a Note that requires the drywell to be declared inoperable should both doors in the air lock fail the air-lock door seal test, SR 3.6.5.2.4.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable drywell air lock cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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 ≥ P_a [11.5] psig. A seal leakage rate limit of ≤ [200] scfh has been established to assure the integrity of the seals. The Frequency of "once within 72 hours after each closing" 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

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 an air lock are designed to withstand the maximum expected post-accident drywell pressure, closure of either door will ensure full drywell OPERABILITY. Thus, the door interlock feature ensures that drywell OPERABILITY is maintained 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 prior to entering drywell but is not required more frequently than 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

interlock mechanism status available to the plant operations personnel.

SR 3.6.5.2.3

Every 7 days the seal air-flask pressure is verified to be ≥ [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 through 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 3.6.5.2.4

This SR requires a test to be performed to verify overall air-lock leakage of the drywell air lock at pressures ≥ P_a [11.5] psig. The Frequency of each COLD SHUTDOWN unless performed in the previous 184 days is considered adequate since the air lock is rarely used and the mostly likely leakage paths, the door seals, are tested after each use. The drywell air lock usually passes this test when it is performed at this Frequency.

This SR has been modified by a Note to indicate 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 capable of providing a fission-product barrier in the event of a DBA.

SR 3.6.5.2.5

This SR ensures that the seal pneumatic-system pressure does not decay at an unacceptable rate. The air-lock seal will maintain drywell OPERABILITY down to a pneumatic pressure of [60] psig. Since the air-lock seal air-flask pressure is verified in SR 3.6.5.2.3 to be ≥ [90] psig, a [30]-psig decay rate 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 was developed considering it is prudent that many

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. 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.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix J, "[Title]."

2. [Unit Name] FSAR, Section [ ], "[Accident Analysis]."

3. Title 10, Code Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

B 3.6 CONTAINER SYSTEMS

B 3.6.5.3 Drywell Isolation Valves (DIVs)

BASES

BACKGROUND

The DIVs, in combination with other accident-mitigation systems, function to ensure that steam and water releases to the drywell are channelled to the suppression pool to maintain the pressure-suppression function of containment and to limit fission-product release during and following postulated Design Basis Accidents (DBA) to values less than 10 CFR 100 (Ref. 1) offsite dose limits.

The OPERABILITY requirements for DIVs help ensure that valves are closed when required, isolation occurs within the time limits specified for those isolation valves designed to close automatically, and drywell leakage is maintained within limits during and after an accident by minimizing potential leakage paths to the suppression chamber airspace or the environment. Therefore, the OPERABILITY requirements provide assurance that drywell leakage assumed in the safety analysis (Ref. 2) for a DBA will not be exceeded. These isolation devices are either passive or active (automatic). Locked-closed manual valves, deactivated automatic valves secured in their closed position, blind flanges, and closed systems are considered passive devices. Closed systems are those systems designed in accordance with 10 CFR 50, Appendix A, GDC 57 (Ref. 3). Check valves, or other automatic valves designed to close without operator's 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 (and possibly loss of drywell OPERABILITY) or leakage that exceeds limits assumed in the safety analysis.

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 is used to supply filtered outside air directly to the drywell through two lines, each containing two primary containment isolation valves (PCIVs) and two DIVs called drywell purge isolation valves (DPIVs). The drywell air is exhausted through a line also containing two DPIVs by means of two fan units, which are part of the Containment Cooling System charcoal filter trains located

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

inside primary containment. After the air is condition 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 DPIVs are seldom open during power operation.

The DPIVs fail closed on loss of instrument air or power. The DPIVs 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). A radiation-monitoring system is provided in the exhaust of the Containment Cooling System to detect high radiation. A high-radiation signal actuates an alarm and automatically initiates closure of the DPIVs. The DPIVs also close in response to any of the following signals:

a. Primary containment and drywell trip logic manual initiation.

b. Reactor low water level.

c. Drywell high pressure.

d. Containment and Reactor Vessel Isolation Control System trip logic manual initiation.

The OPERABILITY requirements for DIVs help ensure that adequate containment leak tightness is maintained during and after an accident by minimizing potential leakage paths to the environment. Therefore, the OPERABILITY requirements provide assurance that containment leakage rates assumed in the safety analysis will not be exceeded.

APPLICABLE SAFETY ANALYSES

The DIVs LCO is to ensure that releases to the drywell are channeled to the suppression pool and are related to the control of offsite radiation doses resulting from major accidents. As delineated in 10 CFR 100, the determination of exclusion areas and low-population zones surrounding a proposed site must consider a fission-product release from the core with offsite release based upon the expected demonstrable leakage rate from the primary containment. This LCO is intended to ensure that releases from the core

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

do not bypass the suppression pool so that the pressure-suppression capability of the primary containment is maintained. Additionally, as part of the drywell boundary, DIVs OPERABILITY is essential to ensure drywell OPERABILITY and maintain doses within limits. The valves must close and remain closed with leakage within limits against peak LOCA-associated drywell pressure. Therefore, the safety analysis of any event requiring isolation of the drywell is applicable to this LCO.

The DBAs that could result in a release of steam, water or radioactive material within the drywell are a LOCA and a main steam line break. In the analysis for each of these accidents, it is assumed that DIVs are either closed or function to close within the required isolation time following event initiation. Analyses (Ref. 2) have shown that the site-boundary dose would not exceed 50% of the 10 CFR 100 limits assuming a recirculation system pipe break from full power with 4-second DPIV closure time following a 1 second delay prior to closure.

The acceptance criteria applied to accidental releases of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following onset of the postulated fission-product release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 (Ref. 2) are a whole-body dose of 25 rem or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use a specified fraction of these limits.

The DIVs and DPIVs satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

DIVs form a part of the drywell boundary. The DIV safety function is to limit bypass leakage and thereby help control

(continued)

(continued)

BASES (continued)

LCO (continued)

of offsite radiation exposures resulting from a DBA. This LCO addresses DIV integrity and stroke time.

The DIVs are considered OPERABLE when isolation times of automatic DIVs are within limits, automatic DIVs actuate on an automatic isolation signal, manual DIVs are closed, and [purge valves that are not qualified close under accident conditions are closed or blocked to limit the maximum valve opening]. The valves covered by this LCO are included (with their associated stroke time for automatic valves) in Reference 4.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are locked-closed, automatic valves are deactivated and secured in their closed position (including check valves with flow through the valve secured), and blind flanges and closed systems are in place. These passive isolation valves/devices are those listed in Reference 2.

[For this facility, OPERABILITY of the DIVs requires OPERABILITY of the following support systems:]

This LCO provides assurance that the DIVs will perform their designed safety functions to mitigate the consequences of accidents that could result in offsite exposure comparable to the 10 CFR 100 limits or some fraction of these limits as established by the NRC staff-approved licensing basis.

[For this facility, those required support systems which upon their failure do not require declaring the DIVs inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a DIV and the justification of whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the drywell. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES.

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

Therefore, the DIVs are not required to be OPERABLE in MODES 4 and 5.

A Note has been added to provide clarification that each penetration flow path is independent and is treated as a separate entity with a separate Completion Time for the purpose of this LCO.

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

When one or more DIVs are inoperable, at least one isolation valve must be verified to be OPERABLE in each affected open penetration. This action may be satisfied by examining logs or other information, to determine if the valve is out of service for maintenance for other reasons. This Required Action is to be completed within 1 hour in order to provide assurance that a drywell penetration is not open causing a loss of drywell OPERABILITY. The 1-hour Completion Time is consistent with LCO 3.6.4.1, "Drywell," and is considered a reasonable length of time to complete the Required Action. Also, this Completion Time is consistent with the Completion Time specified for PCIVs in LCO 3.6.1.3.

Required Actions of Condition A are modified by a Note allowing DIVs, except the purge valves [which are not qualified to close under accident conditions], to be opened intermittently under administrative control. These administrative controls consists of stationing a dedicated operator, who is continuous communication with the control room, at the controls of the valve. In this way, the penetration can be rapidly isolated if a valid drywell isolation signal is indicated. The provisions of LCO 3.0.4 apply. Due to the size of the purge line penetration, and the fact that those penetrations can exhaust directly from the drywell atmosphere to the environment, these valves may not be opened under administrative control.

In the event one or more DIVs are inoperable, either the inoperable valve must be restored to OPERABLE status or the affected penetration 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

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

closed and deactivated automatic DIV, a closed manual valve, a blind flange, or a check valve with flow through the valve secured. One of these two Required Actions must be completed within the 4-hour Completion Time. The 4-hour Completion Time is reasonable considering the time required to isolate the penetration and the relative importance of maintaining drywell OPERABILITY during MODE 1, 2, and 3. Also, this Completion Time is consistent with the Completion Time specified for PCIVs in LCO 3.6.1.3.

For affected penetrations that cannot be restore to OPERABLE status with the applicable Completion Time and have been isolated in accordance with Required Action A.2.2.1, 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. The Completion Time allowed for this is prior to entering MODE 3 from MODE 4, but not more often than 92 days. The Completion Time of 92 days was developed based on Inservice Inspection and Testing Program requirements to perform valve testing at least once every 92 days. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside drywell and capable of potentially being mispositioned are in the correct position. Since these valve are inside primary containment, the time period specified as "prior to enter MODE 3 from MODE 4, but not more often than every 92 days," is based on engineering judgement and is considered reasonable in view of the inaccessibility of the valves and other administrative controls that will ensure that valve misalignment is an unlikely possibility. Also, this Completion Time is consistent with the Completion Time specified for PCIVs in LCO 3.6.1.3.

Required Actions of Condition A are further modified by a second Note stating that Required Action A.1 is not applicable to penetrations that have only one isolation valve. If the single isolation valve is inoperable, the intent is to go directly to Required Action A.2.1.

[For this facility, systems with single isolation valves are as follows:] The justification for a Completion Time of

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

4 hours is analogous to that for lines with two isolation valves. [For this facility, the second Note applies only to the following type of lines:]

B.1

With one or more DIVs inoperable in one or more penetration flow paths, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support DIVs within a Completion Time of [ ] hours. The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition B.

Required Action B.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of DIVs have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition B of this LCO.]

[For this facility, the identified supported systems Required Actions are as follows:]

C.1

With one or more DIVs inoperable in one or more penetration flow paths, and one or more support or supported features, or both, inoperable associated with the other redundant penetration flow paths, there is the loss of functional capability, and LCO 3.0.3 must be immediately entered. However, if the support or supported feature LCO, or both, take into consideration the loss of function, then LCO 3.0.3 may not need to be entered.

An example illustrating the loss of function situation is presented in B 3.6.1.3, "Primary Containment Isolation Valves."

D.1 and D.2

If the Required Actions and associated Completion Times are not met, the plant must be placed in a MODE in which the LCO

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.3.1

Each [ ]-inch DPIV is required to be verified sealed-closed at 31-day intervals. This Surveillance is intended to be used for DPIVs 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 DPIV opening. Detailed analysis of these [20]-inch DIVs failed to conclusively demonstrate their ability to close during a LOCA in time to prevent offsite dose limits from exceeding 10 CFR 100 limits (Ref. 1) or some fraction, as established in the NRC-staff approved licensing basis. Therefore, these valves are required to be in sealed-closed position during MODES 1, 2, and 3. These [20]-inch DIVs 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 Surveillance interval is a result of the NRC resolution of Generic Issue B-24 related to purge valve use during plant operations (Ref. 5).

SR 3.6.5.3.2

This SR ensures that the [20]-inch DPIVs are closed as required or, if open, open for an allowable reason. This SR is intended to be used for DPIVs 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 that these valves may be opened for pressure control, as low as reasonably achievable and air-quality considerations for personnel entry, and Surveillance tests that require the valve to be open. The 31-day Surveillance interval is consistent with the valve requirements discussed under SR 3.6.5.3.1.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.3.3

This SR requires verification that all manual DIVs and blind flanges that are required to be closed during accident conditions are closed. The SR helps to ensure that post-accident leakage of radioactive fluids or gases outside of the boundary is within design limits. For these valves that are inside primary containment, the Surveillance interval specified as "prior to entering MODE 3 from MODE 4 but not more often than once every 92 days" is appropriate since these valves and flanges are operated under administrative control and the probability of their misalignment is low.

A Note has been added to this SR that allows normally locked- or sealed-closed isolation valves to be opened intermittently under administrative controls. The administrative 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 valid drywell isolation signal is indicated. An additional 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. The provisions of LCO 3.0.4 apply.

SR 3.6.5.3.4

Demonstrating that the isolation time of each power-operated and automatic DIV 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 Inspection and Testing Program, but must not exceed 92 days.

SR 3.6.5.3.5

Automatic DIVs close on a drywell isolation signal to prevent leakage of radioactive material from the drywell following a DBA. This SR ensures each automatic DIV will actuate to its isolation position on a drywell isolation signal. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

a plant outage since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. Operating experience has shown these components usually pass this SR when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.5.3.6

Each [ ]-inch DPIV is required to be blocked to limit valve opening to no more than [50]%. This SR is intended to be used for DPIVs that can only be qualified to close under accident conditions by limiting the maximum valve opening. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. Operating experience has shown 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.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."
2. [Unit Name] FSAR, Section [ ], "[Accident Analysis]."
3. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," General Design Criterion 57, "Closed System Isolation Valves."
4. [Unit Name] FSAR, Section [ ], "[Containment Systems]."
5. Generic Issue B-24 "Containment Purge Valve Reliability."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.4 Drywell Pressure

BASES

BACKGROUND

The primary containment serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA), such that offsite radiation exposures are maintained within the requirements of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100).

Drywell-to-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-containment differential pressure could result in overflow over the weir wall.

The limitation on negative drywell-to-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-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. 2). The initial drywell internal pressure affects the drywell pressure response to a LOCA

(continued)

(continued)

APPLICABLE SAFETY ANALYSES (continued)

(Ref. 2) and the suppression pool swell load definition (Ref. 3).

Additional analyses (Refs. 4 and 5) 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 probability of weir-wall overflow is minimized after an inadvertent upper pool dump.

Drywell pressure satisfies Criterion 2 of the NRC Interim Policy Statement.

LCO

A limitation on the drywell-to-primary containment differential pressure of between [-0.26] and [+2.0] psid is required to assure 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. As a result, drywell OPERABILITY is ensured.

[For this facility, the following support systems are required to be OPERABLE to ensure drywell-to-primary containment differential pressure channel OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the drywell-to-primary containment differential inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the drywell. 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-containment differential pressure limitation is not required in MODE 4 or 5 to ensure drywell OPERABILITY.

(continued)

BASES (continued)

ACTIONS

A.1

With drywell-to-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 Required Actions of LCO 3.6.5.1, "Drywell," which requires the drywell to be restored to OPERABLE status within 1 hour.

In the event that the required drywell pressure channels are found inoperable, the drywell-to-primary containment differential pressure is considered to be not within limits and Required Action A.1 applies.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if drywell-to-containment differential pressure cannot be restored to within limits in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in a 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-containment differential pressures 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 and pressure instrument drift 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.

(continued)

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Central Distance."
2. [Unit Name] FSAR, Section [6.2.2], "[Title]."
3. [Unit Name] FSAR, Section [3.8], "[Title]."
4. [Unit Name] FSAR, Section [6.2.1.1.6], "[Title]."
5. [Unit Name] FSAR, Section [6.2.7], "[Title]."

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 assures 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 Interim Policy Statement.

LCO

If the initial drywell average air temperature is less than or equal to the LCO temperature limit, the peak accident

(continued)

(continued)

BASES (continued)

LCO (continued)

temperature can be maintained below the drywell design temperature during a DBA. This ensures the ability of the drywell to perform its design function.

[For this facility, the following support systems are required to be OPERABLE to ensure drywell air temperature channel OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the drywell air temperature channel inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the drywell. 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 or to prepare the plant for an orderly shutdown.

In the event that the required drywell air temperature channels are found inoperable, the drywell air temperature is considered to be not within limits and Required Action A.1 applies.

B.1 and B.2

If the drywell average air temperature cannot be restored to within the limit in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowable Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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 distributed, an arithmetic average is an accurate representation of actual drywell average temperature.

The 24-hour Frequency of the SR was developed considering operating experience related to variations in drywell average air temperature variations and temperature instrument drift 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. [Unit Name] FSAR, Section [6.2], "[Containment Systems]."

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 weirwall overflow into the drywell. Rapid weirwall overflow must be controlled, in a large-break LOCA, so that essential equipment and systems located above the weirwall 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 cause the primary containment to become inoperable, 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 containment 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 weirwall 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 weirwall overflow that could cause drag and impact loadings on essential equipment and systems in the drywell above the weirwall. 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 Interim Policy Statement.

LCO

The LCO assures 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.

[For this facility an OPERABLE drywell post-LOCA and drywell purge vacuum relief subsystems constitute the following:]

In addition a drywell post-LOCA and drywell purge vacuum relief subsystems are considered OPERABLE when they satisfy the requirements set forth by the Surveillances.

[For this facility, the following support systems are required to be OPERABLE to ensure Drywell Vacuum Relief System OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the Drywell Vacuum Relief System inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a Design Basis Accident (DBA) could cause pressurization of primary containment. Therefore, Drywell Vacuum Relief System OPERABILITY is required during

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

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 MODES 4 or 5 to ensure primary containment OPERABILITY and control rapid weirwall overflow.

ACTIONS

A.1 and A.2

(With any of the combinations of inoperable subsystems listed in Condition A, the inoperable subsystem(s) must be closed within 1 hour.)

This assures that drywell bypass leakage would not result if a postulated LOCA were to occur. The 1-hour Completion Time is consistent with LCO 3.6.5.1, "Drywell," and is considered a reasonable length of time needed to complete the Required Action. The inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, 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, reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

B.1, B.2, C.1 and C.2

With two drywell purge vacuum relief subsystems inoperable, or with two drywell post-LOCA and one drywell purge vacuum relief subsystem inoperable, the inoperable subsystems must be closed within 1 hour. In this Condition only one [10]-inch line remains available. At least one inoperable subsystem must be restored to OPERABLE status within 72 hours. The 72-hour Completion Time takes into account the redundant capability afforded by the remaining subsystems, reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable drywell vacuum relief subsystem(s) cannot be closed or restored to OPERABLE status in the associated Completion Time or when two drywell purge vacuum relief subsystems inoperable and one or two drywell post-LOCA vacuum relief subsystem(s) inoperable. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power 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 (except when being tested in accordance with SR 3.6.5.6.2 and SR 3.6.5.6.3 or when the vacuum breakers are performing their intended design function) to ensure that this potential large bypass leakage path is not present. This SR 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 [illegible] psid between the drywell and primary containment is maintained for [1] hour without makeup. The 7-day Frequency is based on engineering judgement and is considered adequate in view of other indications of vacuum breaker or isolation valve status available to the plant operations personnel and has been shown to be acceptable through operating experience.

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 assures that the safety analysis assumptions are valid. The 31-day frequency of this SR was developed based upon Inservice Inspection and Testing Program requirements to perform valve testing at least once per 92 days. A 31-day

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Frequency was chosen to provide additional assurance that the vacuum breakers and their associated isolation valves are OPERABLE.

SR 3.6.5.6.3

Demonstration of the vacuum breaker opening setpoint is necessary to assure that the safety analysis assumption that the vacuum breaker will open fully at a differential pressure of [0.5] psid is valid. The 18-month Frequency was developed considering it is prudent that this Surveillance be performed only during a plant outage. For this facility the 18-month Frequency has been shown to be acceptable through operating experience and is further justified because other Surveillances performed at shorter Frequencies convey the proper functioning status of each vacuum breaker.

REFERENCES

1. [Unit Name] FSAR, Section [6.2], "[Title]."

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 plant auxiliaries, such as Residual Heat Removal (RHR) System heat exchangers, standby diesel generators, and room coolers for Emergency Core Cooling System (ECCS) equipment, which are required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The SSW System also provides cooling to plant 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 (HPCS) service water pump (one per subsystem), are each sized so either can 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 Division I and II, respectively.

The UHS has been defined as that complex of water sources, including necessary retaining structures (e.g., a pond with its dam or a river with its dam), and the canals or conduits connecting the sources (Ref. 1). If cooling towers or portions thereof are required to accomplish the UHS safety functions, they should satisfy the same requirements as the sink. The two principal safety functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

A variety of complexes is used to meet the requirements for a UHS. A lake or an ocean may qualify as a single source. If the complex includes a water source contained by a fabricated structure it is likely that a second source will have been required.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

The basic performance requirements are that a 30-day supply of water (Ref. 1) be available, and that the design bases temperatures of safety-related equipment are not exceeded. Basins of cooling towers generally include less than a 30-day supply of water, typically 7 days or less. Assurance of a 30-day supply is then dependent on other sources and make-up systems for replenishing the source in the cooling tower basin. For smaller basin sources which may be as small as a one-day supply, the systems for replenishing the basin and the backup sources become of sufficient importance that the makeup system itself may be required to meet the same design criteria as an engineered safety feature (ESF) (e.g., single failure considerations), and multiple make-up water sources may be required.

It follows that the many variations in the UHS configurations will result in many plant-to-plant variations in OPERABILITY determinations and in SRs. The Actions and SRs for this LCO are illustrative for a UHS consisting of a cooling tower with makeup water and a river.

A typical UHS complex consists of one concrete makeup water basin with one or more cooling towers and two or more independent fan cells per cooling tower (for one division), and cooling water pumped from a river (for the other division). Cooling water is pumped from the cooling tower basin and river 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 from one division is discharged to the cooling tower where the heat is rejected through direct contact with ambient air then returned to the makeup water basin. Water from the other division is discharged to the river. Normal makeup for the basin is provided automatically by the [Plant] Service Water (PSW) System.

Subsystems A and B supply cooling water to redundant equipment required for a safe reactor shutdown. Additional 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 Reference 2. 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.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

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. 2). The ability of the SSW System to support long-term cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in References 2, 3 and 4. 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 core spray pumps). Also the ability to provide onsite emergency AC power is dependent on the ability of the SSW System to cool the diesel generators.

[The safety analyses for long-term containment cooling were performed (Ref. 2) for a LOCA concurrent with a loss-of-offsite power, and minimum available diesel generator power. The worst-case single failure that would affect the performance of the SSW System is the failure of one of the two standby diesel generators, which would in turn affect one SSW subsystem. Reference 2 discusses SSW System performance during these conditions.]

The SSW System together with the UHS satisfy Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

The OPERABILITY of subsystem A (Division I) and subsystem B (Division II) 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.

An OPERABLE subsystem has an OPERABLE UHS with its associated pump OPERABLE, and an OPERABLE flow path capable of taking suction from the associated SSW cooling water source and transferring the water to the appropriate plant equipment. OPERABILITY of the UHS is based on a maximum water temperature of [90]°F with OPERABILITY of subsystem A requiring a minimum basin water level at or above elevation [ ] ft [ ] inches mean sea level (which is equivalent to an indicated level of greater than or equal to [ ] ft), and [two] OPERABLE cooling tower fans; and OPERABILITY of subsystem B requiring a minimum water level in the pump well of the intake structure of [ ] ft [ ] inches mean sea level (or an indicated level of ≥ [ ] ft).

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.

[For this facility, the following support systems must be OPERABLE to ensure SSW System and UHS OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the SSW System and UHS inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of the SSW System and UHS and the justification for whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, the SSW System and UHS are required to be OPERABLE to support OPERABILITY of the equipment serviced

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

by the SSW System, and required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the SSW System are determined by the systems it supports.

For this LCO, Note has been added to provide clarification that all components of the SSW System and UHS are treated as an entity with a single Completion Time.

ACTIONS

A.1 and A.2

Required Action A.1 assures that the required cooling capability will be available in the event of a DBA.

This Action may be satisfied by examining logs or other information to determine whether the cooling tower fans may be out of service for maintenance or other reasons. It does not mean that it is necessary to perform the SRs needed to demonstrate OPERABILITY of the fan. If there is not one cooling tower fan per cooling tower OPERABLE, Condition E must be immediately entered. The Completion Time of 1 hour is sufficient for the plant operations personnel to make this determination.

For Action A.2, if one cooling tower fan per cooling tower is inoperable, the inoperable cooling tower fans must be restored to OPERABLE status within 7 days before action must be taken to reduce power. The specified Completion Time is consistent with other LCOs for loss of one-half of a 200%-capacity train of an ESF system.

The 7-day Completion Time is based on the low probability of an accident occurring during the 7 days that one cooling tower fan is inoperable, the number of available systems, and the time required to reasonably complete the Required Action.

B.1

With one SSW subsystem inoperable, the remaining OPERABLE subsystem provides adequate heat removal capacity following a DBA. The Completion Time of 72 hours is allowed to

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

restore the SSW subsystem to OPERABLE status. The Completion Time takes into account the redundant SSW System capabilities afforded by the OPERABLE subsystem and the low probability of an accident during this time period, and is consistent with the completion Time to restore an inoperable diesel generator or one low-pressure ECCS division to OPERABLE status.

C.1

With one SSW subsystem inoperable, or less than [one] cooling tower fan(s) inoperable in one or more cooling towers, or both instances, verify that the Required Actions have been initiated for those supported systems declared inoperable by the inoperability of the support SSW subsystem or cooling tower fans within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition C.

Required Action C.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of SSW subsystem or cooling tower fans have been initiated by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition C of this LCO.]

[For this facility, the identified supported systems' Required Actions are as follows:]

D.1

With one SSW subsystem inoperable, or no more than [one] cooling tower fan(s) inoperable in one or more cooling towers, or both instances; and one or more required support or supported features inoperable that are associated with the other redundant SSW subsystem or cooling tower fans; a loss-of-function capability results, and LCO 3.0.3 must be entered immediately. However, if the support or supported features' LCOs take into consideration the loss-of-function situation, then LCO 3.0.3 may not need to be entered.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

E.1 and E.2

If the Required Actions and associated Completion Times are not met, or both SSW subsystems are inoperable, or the UHS is determined inoperable for reasons other than Condition A, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours, and in MODE 4 within 36 hours. The allowed Completion Times are reasonable times, based on experience, to reach the required MODES from full power in an orderly manner without challenging plant systems.

This Condition includes the situation where MODE 4 may not be achievable within the specified Completion Time because of the inoperable SSW subsystems, in which case the reactor coolant temperature should be maintained as low as practicable using an alternate decay-heat-removal method. When an adequate complement of components is available, the plant should be placed in MODE 4. [For this facility, an alternate decay-heat-removal method consists of the following:]

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This surveillance verifies that the cooling tower basins have sufficient cooling water (as measured by basin water level) to satisfy the design basis of 30-day cooling capability with no external makeup source. 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 inside the pump wells 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). If a temporary weir is in place, the [river] level must also correspond to the level in the pump well of the intake

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

structure. 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.

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 was developed considering 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. It has also been shown to be acceptable through operating experience.

SR 3.7.1.5

Verifying the correct alignment for manual, power-operated, and automatic valves in the SSW 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. This SR does not require any testing or valve manipulation, nor does not it apply to valves that cannot be inadvertently misaligned, such as check valves. Rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

The 31-day Frequency of this SR was derived from Inservice Inspection and Testing Program requirements for performing valve testing at least once every 92 days. The Frequency was further justified in view of other procedural controls

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

governing valve operations and to provide added assurance of correct valve positions.

SR 3.7.1.6

This surveillance verifies 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 surveillance also verifies the automatic start capability of the SSW pump in each subsystem.

Operating experience has shown that these components usually pass the SR when performed on the 18-month Frequency. Therefore, this Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants," Revision 2, January 1976.
2. [Unit Name] FSAR, Chapter [9], "[Auxiliary Systems]."
3. [Unit Name] FSAR, Chapter [6], "[Engineered Safety Features]."

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 III] HPCS System.

For the purposes of this technical specification, the HPCS SWS consists of the Ultimate Heat Sink (UHS), one cooling water header (a subsystem 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) and is described in B 3.7.1.

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 III] 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 (DBA) or transient, the HPCS SWS will operate automatically and without operator action.

APPLICABLE SAFETY ANALYSES

No safety analysis explicitly requires a HPCS SWS; however, it is required to support the HPCS Emergency Core Cooling System (ECCS) function (Ref. 1). Safety analyses for the ECCS are addressed in B 3.5.1 and B 3.5.2.

The HPCS SWS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The OPERABILITY of the HPCS SWS is required to ensure that the HPCS System will operate as required. An OPERABLE HPCS

(continued)

(continued)

BASES (continued)

LCO (continued)

SWS has an OPERABLE UHS, an OPERABLE pump, and an OPERABLE flow path capable of taking suction from the associated SSW source and transferring the water to the appropriate plant equipment.

The OPERABILITY of the UHS is specified in LCO 3.7.1.

[For this facility, the following support systems must be OPERABLE to ensure HPCS SWS OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the HPCS SWS inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of the HPCS SWS and the justification for whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

The requirements for OPERABILITY of the HPCS SWS, including the cooling tower basins, are governed by the required OPERABILITY of the HPCS equipment serviced by the HPCS SWS.

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 [72 hours] are allowed to restore the HPCS SWS to OPERABLE status.

The [72 hours] for a [Division III] HPCS System inoperability is based upon the risk-significance of the [Division III] HPCS diesel generator in coping with a station blackout (SBO).

The Completion Time for a [Division III] diesel generator (and, hence, HPCS SWS) may be increased from [72 hours] to [14 days] provided:

a. The [Division III] sole function is support of the HPCS function; and

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

b. Calculations show that the increase in the core melt frequency for an SBO with an inoperable [Division III] diesel generator are acceptably low.

If other engineered safety features are supported by [Division III], or if calculations show that the increase in core melt frequency for a SBO with an inoperable [Division III] diesel generator are unacceptably high, then the Completion Time for an inoperable [Division III] HPCS SWS shall be [72 hours].

B.1

With the HPCS SWS inoperable, verify that the Required Actions have been initiated for those supported systems declared inoperable by the inoperability of the support HPCS SWS within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition B.

Required Action B.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of HPCS SWS have been initiated by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Conditions C of this LCO.]

[For this facility, the identified supported systems Required Actions are as follows:]

C.1 and C.2

If the Required Actions and associated Completion Times are not met, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours, and in MODE 4 within 36 hours. The allowed Completion Times are reasonable times, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

This Condition includes the situation where MODE 4 may not be achievable within the specified Completion Time because of the inoperable SSW subsystems, in which case the reactor coolant temperature should be maintained as low as practicable using an alternate decay-heat-removal method. When an adequate complement of components are available, the plant should be placed in MODE 4. [For this facility an alternate decay-heat-removal method consists of the following:]

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

Verifying the correct alignment for manual, power-operated, and automatic valves 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 apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in 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 potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31-day Frequency of this SR was derived from Inservice Inspection and Testing Program requirements for performing valve testing at least once every 92 days. The Frequency was further justified in view of other procedural controls governing valve operations and to provide added assurance of valve correct positions.

SR 3.7.2.2

This surveillance 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.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	Operating experience has shown that these components usually pass the SR when performed on the 18-month Frequency. Therefore, this Frequency was concluded to be acceptable from a reliability standpoint.
REFERENCES	1. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.7 PLANT SYSTEMS

B 3.7.3 Control Room Air Intake, Recirculation, and Purification (AIRP) System

BASES

BACKGROUND

The Control Room AIRP System provides a radiologically controlled environment from which the plant can be safely operated following a Design Basis Accident (DBA).

The safety-related function of the AIRP System used to control radiation exposure consists of two independent and redundant high-efficiency air-filtration subsystems. 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 for emergency treatment of recirculated air or outside supply air, 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 AIRP 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 AIRP 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. Outside air is taken in at the normal ventilation intake and is mixed with the recirculated air before being passed through one of the charcoal adsorber filter systems for removal of airborne radioactive particles.

The air entering the control room is continuously monitored by radiation and toxic gas detectors. One detector output above the setpoint will cause actuation of the emergency radiation mode or toxic gas isolation mode, as required. The actions of the toxic gas isolation mode are more restricted and will override the actions of the emergency radiation mode.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

The AIRP System is designed to maintain the control room environment for 30-days continuous occupancy after a DBA without exceeding a 5-rem whole-body dose. A single AIRP subsystem will pressurize the control room to about [0.1] inches water gauge to prevent infiltration of air from surrounding buildings, and provide an air exchange rate in excess of [25]% per hour. AIRP System operation in maintaining the control room habitable is discussed in References 1 and 2.

APPLICABLE SAFETY ANALYSES

The ability of the Control Room AIRP System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in References 3 and 4. The isolation mode of the AIRP System is assumed to operate following a loss-of-coolant accident (LOCA), main steam line break (MSLB), fuel-handling accident, and control rod drop accident (CRDA) (Ref. 1). The radiological doses to control room personnel as a result of the various DBAs are summarized in Reference 5. Single-failure criteria are met, since all active components are located in the redundant portions of the systems. No single active or passive electrical failure will cause the loss of outside or recirculated air from the control room.

The Control Room AIRP System satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two redundant subsystems of the Control Room AIRP System are required 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 Control Room AIRP 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;

(continued)

(continued)

BASES (continued)

LCO (continued)

b. HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions;

c. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained; and

d. SRs are met.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

[For this facility, the following support systems must be OPERABLE to ensure Control Room AIRP System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the Control Room AIRP System inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, the AIRP System must be OPERABLE to control operator exposure during and following a DBA, since the DBA could lead to a fission-product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. During handling of irradiated fuel in the primary or secondary containment, or when moving loads over irradiated fuel, or during CORE ALTERATIONS, or operations with a potential for draining the reactor vessel (OPDRVs), the AIRP System must be OPERABLE. Significant radioactive releases can be postulated to occur under these situations, and control room isolation could be required as well.

ACTIONS

A.1

With one AIRP subsystem inoperable, the inoperable AIRP subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE AIRP subsystem is adequate to perform control room radiation protection. The

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

7-day Completion Time is based on the low probability of a DBA occurring during this time period, and the fact that the remaining subsystem can provide the required capabilities.

The concurrent failure of two AIRP subsystems would result in the loss-of-functional capability; therefore, LCO 3.0.3 must be entered immediately.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable AIRP subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE that minimizes risk. This is done by placing the plant in at least MODE 3 within 12 hours, and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

C.1

During handling irradiated fuel in the primary or secondary containment, or when moving loads over irradiated fuel, or during CORE ALTERATIONS or OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE AIRP subsystem may be placed in the isolation mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation will occur, and that any active failure would be readily detected.

Required Action C.1 is modified by a Note to alert the operator to place the system in the toxic gas protection mode if the toxic gas, auto-swapover capability is inoperable.

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

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactivity that might enter the control room. This places the plant in a condition that minimizes risk.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

Also, if applicable, actions must be 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.

The Required Actions for Condition C are modified by a Note saying that LCO 3.0.3 is not applicable. If handling fuel while in MODE 1, 2 or 3, the fuel handling is independent of reactor operations. Therefore, inability to suspend handling of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

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

During handling of irradiated fuel or other loads in the primary or secondary containment, or during CORE ALTERNATIONS or OPDRVs, with two AIRP subsystems inoperable, the Required Action is to immediately suspend activities that present a potential for releasing radioactivity that might enter the control room. This places the plant in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be 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.

The Required Actions for Condition D are modified by a Note that LCO 3.0.3 is not applicable. If handling fuel while in MODE 1, 2 or 3, the fuel handling is independent of reactor operations. Therefore, inability to suspend handling of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

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 each subsystem once every month provides an adequate check on this system. Monthly heater operation drives out any moisture accumulated in the charcoal from humidity in the ambient air. Systems without heaters need only be operated for 15 minutes to demonstrate the function of the system. Furthermore, the 31-day Frequency was developed considering the known reliability of the equipment and the two-subsystem redundancy available.

SR 3.7.3.2

This SR demonstrates the performance of the HEPA and charcoal filters.

The required testing for the AIRP filters is detailed in the Ventilation Filter Testing Program. The program specifies the required tests and their frequencies. The tests are performed in accordance with Regulatory Guide 1.52 (Ref. 6).

SR 3.7.3.3

This SR demonstrates that each AIRP subsystem starts and operates on an actual or simulated actuation signal. The 18-month Frequency is specified in Regulatory Guide 1.52 (Ref. 6).

SR 3.7.3.4

This SR demonstrates 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 AIRP System. During the emergency mode of operation, the AIRP 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 AIRP System is designed to maintain this positive pressure

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

at a flow rate of [400] cfm to the control room in the isolation pressurization mode. The 18-month Frequency is consistent with the guidance provided in Section 6.4 of NUREG-0800 (Ref. 7).

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. [Unit Name] FSAR, Chapter [6], "[Engineered Safety Features]."

4. [Unit Name] FSAR, Chapter [15], "[Accident Analyses]."

5. [Unit Name] FSAR, Section [ ], "[Title]."

6. Regulatory Guide 1.52, "Design, Testing and Maintenance Criteria for Post Accident Engineered Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," Revision 2, March 1978.

7. NUREG-0800, Section 6.4, "Standard Review Plant," Revision 2, "Control Room Habitability System," July 1981.

B 3.7 PLANT SYSTEMS

B 3.7.4 Control Room Heating, Ventilation, and Air Conditioning (HVAC) System

BASES

BACKGROUND

The Control Room HVAC System provides temperature control for the control room following isolation of the control room.

The HVAC System consists of two independent, redundant subsystems which 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 HVAC System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem will provide the required temperature control to maintain a suitable control room environment with temperatures between [70]°F and [85]°F for a sustained occupancy of 12 persons. The HVAC System operation in maintaining the control room temperature is discussed in References 1 and 2.

APPLICABLE SAFETY ANALYSES

The design basis of the HVAC System is to maintain the control room temperature for 30 days continuous occupancy.

The Control Room HVAC System components are arranged in redundant safety-related subsystems. During emergency operation, the HVAC System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single active failure of a component of the HVAC 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 HVAC System is designed in accordance with Seismic Category I requirements. The HVAC System is capable of removing sensible- and latent-heat loads from the control room, which includes consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The Control Room HVAC System satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two independent and redundant subsystems of the Control Room HVAC System are required to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in exceeding equipment temperature limitations.

The HVAC 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. In addition the Control Room Air Intake, Recirculation, and Purification System must be OPERABLE to the extent that air circulation can be maintained.

[For this facility, the following support systems must be OPERABLE to ensure Control Room HVAC System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the Control Room HVAC System inoperable and their justification are as follows:]

APPLICABILITY

In MODE 1, 2, or 3, the HVAC System must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY limits following control room isolation.

During CORE ALTERATIONS, or when moving loads over irradiated fuel, or when handling irradiated fuel in the primary or secondary containment, or during operations with a potential for draining the reactor vessel (OPDRVs), the HVAC System must be OPERABLE.

(continued)

BASES (continued)

ACTIONS

A.1

With one control room HVAC subsystem inoperable, the inoperable HVAC subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE HVAC subsystem is adequate to perform the control room air conditioning function. The 30-day Completion Time is based on the low probability of an event requiring control room isolation, the consideration that the remaining train can provide the required protection, and the availability of alternate safety and non-safety cooling methods. [For this facility, the alternate cooling methods are as follows:]

The concurrent failure of two HVAC subsystems would result in the loss-of-functional capability; therefore, LCO 3.0.3 must be entered immediately.

B.1 and B.2

In MODE 1, 2, or 3, the plant must be placed in a MODE which minimizes the risk if the inoperable HVAC subsystem cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours, and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

C.1

During CORE ALTERATIONS, OPDRVs, movement of irradiated fuel in the primary or secondary containment, or movement of loads over irradiated fuel, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE HVAC subsystem should be immediately placed in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures which would prevent automotive actuation will occur, and that any active failure would be readily detected.

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

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing

(continued)

(continued)

ACTIONS (continued)

radioactivity which might require isolation of the control room. This places the plant in a condition which minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be 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.

The Required Actions for Condition C are modified by a Note that LCO 3.0.3 is not applicable. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent of reactor operations. Therefore, inability to suspend handling of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

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

During CORE ALTERATIONS, OPDRVs, or movement of irradiated fuel or other loads over irradiated fuel in the primary or secondary containment with two HVAC subsystems inoperable, the Required Action is to immediately suspend activities that present a potential for releasing radioactivity which might require isolation of the control room. This places the plant in a condition which minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be 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.

The Required Actions for Condition D are modified by a Note stating that LCO 3.0.3 is not applicable. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

of reactor operations. Therefore, inability to suspend handling of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the heat-removal capability of the system is sufficient to remove the assumed heat load in the control room. The test is performed at a 18-month Frequency and consists of a combination of testing and calculation. The 18-month Frequency is appropriate since significant degradation of the HVAC System is not expected over this time period.

REFERENCES

1. [Unit Name] FSAR, Section [6.4], "[Title]."

2. [Unit Name] FSAR, Section [9.4.1], "[Title]."

B 3.7 PLANT SYSTEMS

B 3.7.5 Main Condenser Offgas

BASES

BACKGROUND	During plant operation, steam from the low-pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Offgas System. The offgas from the main condenser normally includes radioactive gases. The Main Condenser Offgas System has been incorporated into the plant 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 flow rate is an initial condition of the offgas system failure event (Ref. 1). The analysis assumes a gross failure in the Offgas System that results in the rupture of the Offgas System pressure boundary. The gross gamma activity flow rate is controlled to ensure that during the event, the calculated offsite doses will be well within the limits of 10 CFR 100, or the NRC staff-approved licensing basis. Main Condenser Offgas satisfies Criterion 2 of the NRC Interim Policy Statement.
LCO	To ensure compliance with the assumptions of the 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 μCi/MWt-sec at 30-minutes decay.

(continued)

(continued)

BASES (continued)

LCO (continued)	The LCO is established consistent with this requirement (RATED THERMAL POWER (RTP) x 100 μCi/MWt-sec x = [ ] 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 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 flow rate limit is exceeded, a limited time is permitted to restore the gross gamma activity flow rate to within the limit. The 72-hour Completion Time is based on engineering judgment, which considered the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the small probability of an Offgas System rupture. B.1 and B.2 If the gross gamma activity flow rate is not restored to within the limits within the associated Completion Time of Required Action A.1, all main steam lines or the SJAE must be isolated. This isolates the 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 based on operating experience of the amount of time required to perform the action from full-power operation in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

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 ≥ 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 flow rate. The Frequencies are considered adequate in view of other instrumentation that continuously monitor the offgas, and has been shown to be acceptable through operating experience.

This SR has been modified by a Note that specifies that the SR is required only when any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Offgas System at significant rates. This exception applies to both required Frequencies and allows the frequency "clock" to begin only when the noted condition is met.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

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 plant 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 (NSSS) rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The bypass system consists of a two-valve chest connected to the main steam lines between the main steam isolation valves (MSIVs) 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 (EHC) System (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] (Ref. 2). Opening of the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure which affects the MINIMUM CRITICAL POWER RATIO (MCPR) during the event. An inoperable Main Turbine Bypass System may result in a MCPR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of the NRC Interim 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 SL MCPR is not exceeded. With the bypass system inoperable, modifications to the MCPR limits (LCO 3.2.2) may be applied to allow continued operation.

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).

[For this facility, an OPERABLE Main Turbine Bypass System consists of the following:]

[For this facility, the following support systems must be OPERABLE to ensure Main Turbine Bypass System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the Main Turbine Bypass System inoperable and their justification are as follows:]

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RATED THERMAL POWER (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 and LCO 3.2.2 sufficient margin to these limits exists below 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the bypass system inoperable (one or more Bypass Valves inoperable), and the MCPR limits for Main Turbine Bypass System are inoperable (as specified in the CORE OPERATING LIMITS REPORT), the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

bypass system to OPERABLE status or adjust the MCPR limits accordingly. The 1-hour Completion Time is based on the time required to reasonably complete the Required Action, and the low probability of an event requiring Main Turbine Bypass System action occurring during this period.

B.1

If the bypass system cannot be restored to OPERABLE status or the MCPR limits for the bypass system inoperable are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation below 25% RTP results in sufficient margin to the required limits, and the bypass system is not required to protect fuel integrity during the [feedwater controller failure, maximum demand event]. The 6-hour Completion Time is based on operating experience to reach the reduced power level from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

Cycling the bypass valves through one complete cycle of full travel, demonstrates that the valves are mechanically OPERABLE and will function when required. The 31-day Frequency of this SR was derived from the Inservice Inspection and Testing Program requirements for performing valve testing at least once every 92 days. Operating experience has shown that these components usually pass the SR when performed on the 31-day Frequency. Therefore, the frequency is concluded to be acceptable from a reliability standpoint.

SR 3.7.6.2

The Main Turbine Bypass System is required to actuate automatically to perform its designed function. This SR demonstrates that with the required system initiation signals, the valves will actuate to their required position.

The 18-month Frequency was developed since it was considered prudent that many surveillances only be performed during a plant outage. This was due to the plant conditions needed

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued) (continued)

to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. Operating experience has shown the 18-month Frequency, which is based on the refueling cycle, to be acceptable from a reliability standpoint.

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 [plant specific documentation]. The 18-month Frequency was developed since it was considered prudent that many surveillances only be performed during a plant outage. This was due to the plant conditicns needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. Operating experience has shown the 18-month Frequency to be acceptable from a reliability standpoint.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. [Unit Name] FSAR, Section [ ], "[Title]."

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. The specified water level also shields and minimizes the general-area dose when the storage racks are at their maximum capacity, and also provides shielding during the movement of spent fuel. A general description of the spent fuel storage pool and upper containment fuel storage pool design is found in Reference 1. The assumptions of the fuel-handling accident are found in Reference 2.
APPLICABLE SAFETY ANALYSES	The water level above the irradiated fuel assemblies is an explicit assumption of the fuel-handling accident (Ref. 2). A fuel-handling accident is evaluated to ensure the radiological consequences (calculated whole-body and thyroid doses at the exclusion area and low-population-zone boundaries) are ≤ 25% of the 10 CFR 100 exposure guidelines (Ref. 3). A fuel-handling accident could release a fraction of the fission-product inventory by breaching the fuel rod cladding (Ref. 4). The fuel-handling accident of Reference 1 is evaluated for the dropping of an irradiated fuel-assembly onto the reactor core. The consequences of a fuel-handling accident over the spent fuel storage pool are no more severe than those of the fuel-handling accident over the reactor core (Ref. 1). The water level in the spent fuel storage pool and upper containment fuel storage pool provides for absorption of water soluble fission-product gases and transport delays of soluble and insoluble gases which must pass through the water before being released to the secondary containment atmosphere. This absorption and transport delay reduce the potential radioactivity of the release during a fuel-handling accident. The fuel pool water level satisfies Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

The specified water level preserves the assumption of the fuel-handling accident analysis (Ref. 2). As such, it is the minimum required for fuel movement within the spent fuel storage pool and upper containment fuel storage pool.

[For this facility, the following constitutes an OPERABLE fuel pool water level:]

[For this facility, the following support systems are required to be OPERABLE to ensure fuel pool water level OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring fuel pool water level inoperable and their justification are as follows:]

APPLICABILITY

This LCO applies whenever irradiated fuel is in the spent fuel storage pool or upper containment fuel storage pool because the potential for a release of fission products exists.

ACTIONS

A.1

When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. With the fuel pool level less than required, the handling of irradiated fuel assemblies in the spent fuel storage pool or upper containment fuel storage pool is immediately suspended. 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. Plant procedures control the movement of loads over the spent fuel in all cases.

A.2

Action must be initiated immediately to restore the water level. Actions must continue until water level is restored to within limits.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Required Actions A.1 and A.2 are modified by a Note which allows an exemption from LCO 3.0.3 and LCO 3.0.4. These LCOs are not applicable as events in the spent fuel storage pool are not affected by MODE level or facility operations.

In the event that the required fuel pool is found inoperable, the fuel pool water level is considered to be not within limits and Required Action A.1 and Required Action A.2 apply.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR verifies 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 pool must be checked periodically. The 7-day Frequency is appropriate since the water volume in the pool is normally stable, water level changes are controlled by plant procedures, and it has been proven to be acceptable through operating experience.

During refueling operations, the level in the fuel pools is in equilibrium with the refueling canal, and the level in the refueling canal is checked daily under SR [3.9.6.1].

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. NUREG-0800, "Standard Review Plan," Section 15.7.4, "Radiological Consequences of Fuel Handling Accidents," Revision 1, July 1981.

4. Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors," March 1972.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

Introduction

The [Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} AC source consist of the offsite power sources [preferred power sources, normal and alternate(s)], and the onsite standby power sources [[Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} diesel generators]. As required by 10 CFR 50, Appendix A, GDC 17, "Electric Power Systems" (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.

{VS-BW,CE,W,BWR/4: The onsite Class 1E AC Distribution System supplies electrical power to [two redundant divisional load groups], with each [division] powered by [an independent Class 1E 4.16 kV ESF bus]. [Each [ESF bus] has at least [one] separate and independent offsite source[s] of power as well as a dedicated onsite diesel generator source.] The [Division 1 and Division 2] ESF systems each provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition. [An electrical power distribution system diagram is provided in Figure B 3.8.1-1.]}

{VS-BWR/6: The onsite 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]. The [Division 1 and 2] [ESF buses] each have at least [one] separate and independent offsite source[s] of power. The [Division 3] [ESF bus] has at least [one] offsite source[s] of power. Each [ESF bus] has a dedicated onsite diesel generator. 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. [An electrical power distribution system diagram is provided in Figure B.3.8.1-1.]}

(continued)

(continued)

"This Figure For Illustration Only. Do Not Use For Operation"

[PLANT SPECIFIC FIGURE]

[inclusion optional]

Figure B 3.8.1-1 (Page 1 of 1)
Electrical Power System

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

The redundant parts of the AC electrical power system are electrically, physically, and functionally independent to the extent that no single failure will cause a total loss of power to redundant safety-related load groups.

A single failure is an occurrence that results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered to be a single failure. Electrical systems are considered to be designed against an assumed single failure if neither a single failure of any active component (assuming passive components function properly) nor a single failure of a passive component (assuming active components function properly) results in a loss of the capability of the system to perform its safety functions.

In the event of a loss of preferred power, the ESF switchgears are automatically connected to the diesel generators in sufficient time for safe reactor shutdown or in sufficient time to mitigate the consequences of a Design Basis Accident (DBA) such as a loss-of-coolant accident (LOCA).

Offsite Sources

Offsite power is supplied to the [plant name] [switchyard(s)] from the transmission network by [two] transmission lines, which come into [the switchyard(s) via [two] right-of-way(s)]. From the [switchyard(s)] [two] electrically and physically separated circuits provide AC power, through [step-down station auxiliary transformers], to the [4.16 kV ESF buses]. The [two] 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.

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 or buses].

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

[PLANT SPECIFIC:
Provide description of any other salient features of the offsite power sources. Items that may be covered include:

a. Circuit breakers and protective relaying;

b. Ability to cross tie offsite circuits so that one circuit may power both ESF buses;

c. Normal at-power and shutdown electrical alignments;

d. Offsite circuit capability;

e. Ability to power ESF buses from the plant's own generator output via the unit auxiliary transformers; and

f. A description, for both the at-power and shutdown lineups, of alternate power availability from alternate offsite power circuits. Include in the description the capability of the alternate circuits, and whether the circuit is immediate or delayed access. If it is a delayed access circuit, describe what has to be done to gain access to the circuit (such as remove generator disconnect links) and whether the actions can be done remotely from the control room. Also state the amount of time required to perform the actions.

g. Discuss whether the sequencer is a support system for the offsite circuits, and whether the circuits are block-loaded with ESF loads, or whether they have the loads sequenced onto them.

h. Define and discuss the physical and functional characteristics of the offsite circuits that make them "separate and independent." Also, "separate" should be defined in terms of firedoors not closed, etc.]

<u>Onsite Sources</u>

The onsite standby power source for each [4.16 kV ESF bus] is a dedicated diesel generator. {VS-BW,CE,W,BWR/4: [Diesel generators (DGs) [11] and [12] are dedicated to ESF buses

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

[11] and [12], respectively].} {VS-BWR/6: [Diesel (DGs) generators [11], [12], and [13] are dedicated to ESF buses [11], [12], and [13], respectively].} A DG starts automatically on {VS-BW,CE,W: [a safety injection signal (SIS) (i.e., low pressurizer pressure or high containment pressure signals)]} {VS-GE:[a LOCA signal (i.e., low reactor water level signal or high drywell pressure signal)]} or on an [ESF bus degraded voltage or undervoltage signal]. The undervoltage trip device senses a severe loss-of-voltage to a level at which electrical equipment would not function. The degraded voltage trip device senses a loss of voltage condition at which the equipment would function, but would sustain damage and become inoperable if operated for extended periods with degraded voltage. Additionally, after the diesel generator has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of [ESF bus] undervoltage or degraded voltage, independent of or coincident with a safety injection signal. The DGs will also start and operate in the standby mode without tieing to the [ESF bus] on a safety injection signal alone. Following the trip of offsite power, a sequencer strips all non-permanent loads from the [ESF bus]. When the DG is tied to the [ESF bus], loads are then sequentially connected to their respective [ESF bus] by their automatic sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent an overburdened DG by automatic load application.

Ratings for [Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} DGs satisfy the requirements of Regulatory Guide 1.9, "Selection, Design, and Qualification of DG Units Used as Onsite Electric Power Systems at Nuclear Power Plants" (Ref. 2). The continuous service rating of each of the DGs is [7,000] kW for [Divisions 1 and 2] {VS-BWR/6: and is [3,000] kW for [Division 3]} with [10]% overload permissible for up to 2 hours in any [24]-hour period. The ESF loads that are powered from the [4.16 kV ESF buses] are listed in Reference 3.

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

Automatic Sequencers

The sequencer(s) is (are) activated by one of two conditions, [ESF bus] undervoltage (UV) or {VS-BW,CE,W: SIS} {VS-GE: LOCA signal}. Upon receipt of either or both of the initiating signals, the following actions will take place:

a. The DGs start;

b. Any test sequence in progress stops;

c. The [ESF bus] of all non-permanent loads (UV only) is stripped;

d. The DG breaker (UV only) closes; and

e. The appropriate loads as determined by the initiating signal energize.

Required plant loads are returned to service in a sequence determined to ensure that the most essential loads are started first while preventing overloading of the DGs in the process. Within [1 minute] after the initiating signal is received, all loads needed to recover the plant or maintain it in a safe condition are returned to service.

The sequencer is an essential support system to [both the offsite circuit and the DG associated with a given ESF bus.] [Furthermore, the sequencer 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].

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in the FSAR, [Chapter 6, "Engineering Safety Features"], and [Chapter 15, "Accident Analyses"], 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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

detail in the Bases for Technical Specifications (TS) 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 3.6 (containment systems).

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one [division] of the onsite or offsite AC sources, DC power sources and associated distribution systems OPERABLE during accident conditions in the event of:

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 NRC Interim Policy Statement.

LCO

As a minimum, the following AC electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E Distribution System {VS-BWR/6: and a third [Division 3] circuit, not necessarily separate and independent from the first two}; and

b. {VS-BW,CE,W,BWR/4: Two} {VS-BWR/6: Three} separate and independent DGs {VS-BW,CE,W,BWR/4: [11] and [12]} {VS-BWR/6: [11], [12, and [13]}, each with:

   1. separate day [and engine-mounted] fuel tanks containing a minimum volume of fuel within the limits specified in SR 3.8.1.8,

   2. a separate Fuel Storage System containing a minimum volume of fuel within the limits specified in SR 3.8.1.9,

(continued)

(continued)

BASES (continued)

LCO (continued)

3. a separate fuel transfer pump capable of meeting SR 3.8.1.16,

4. lubricating oil storage containing a minimum total volume of lubricating oil within the limits specified in SR 3.8.1.10,

5. capability to transfer lubricating oil from storage to the DG unit, and

6. separate air-start receivers containing a minimum air pressure within the limits of SR 3.8.1.7.

In addition, [one required automatic load sequencer per ESF bus] shall be OPERABLE. {VS-BWR/6: [PLANT SPECIFIC: In general, [Division 3] does not have a load sequencer since it has only one large load, i.e., high pressure core spray (HPCS) pump. In such cases the LCO should refer to the [Division 1 and 2] sequencers only.]}

For the offsite circuits, DGs, and sequencers to be OPERABLE, they must be capable of performing their intended function, have all support systems OPERABLE, and have successfully completed all SRs.

[Each facility will define what constitutes an OPERABLE offsite circuit, including the components of the circuit, such as breakers, transformers, switches, interrupting devices, protective relays, cabling and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF buses.]

[For this facility, as a minimum, the following support systems are required OPERABLE to assure offsite circuit OPERABILITY:]

[ ]

Inoperability of any of the offsite circuit support systems results immediately in an inoperable offsite circuit as per the definition of OPERABILITY; however, exceptions are

(continued)

(continued)

BASES (continued)

LCO (continued)

allowed for specific support systems, provided that a justification is given. Therefore, upon the inoperability of the following support systems for an offsite circuit, the declaration of an inoperable offsite circuit may be delayed:

[ ]

The justification for delaying the declaration of offsite circuit inoperability for each of the above items is as follows:

[ ]

[Each facility will define what constitutes an OPERABLE DG, including the components of the DG, such as the diesel engine, generator, Fuel Storage System, starting and control air, combustion air intake and exhaust, cooling system, lubricating oil, ventilation, and DG output breaker.]

[For this facility, as a minimum, the following support systems are required OPERABLE to assure DG OPERABILITY:]

[ ]

Inoperability of any of the DG support systems results immediately in an inoperable DG as per the definition of OPERABILITY; however, exceptions are allowed for specific support systems provided that a justification is given. Therefore, upon the inoperability of the following support systems for a DG, the declaration of an inoperable DG may be delayed:

(continued)

(continued)

BASES (continued)

LCO (continued)

[ ]

The justification for delaying the declaration of DG inoperability for each of the above items is as follows:

[ ]

[Each facility will define what constitutes an OPERABLE [automatic sequencer, including the components of the sequencer such as programmable logic arrays].

[For this facility, as a minimum, the following support systems are required OPERABLE to assure [automatic sequencer] OPERABILITY:]

[ ]

Inoperability of any of the [automatic sequencer] support systems results immediately in an inoperable [automatic sequencer] as per the definition of OPERABILITY; however, exceptions are allowed for specific support systems provided that a justification is given.

Therefore, upon the inoperability of the following support systems for an [automatic sequencer], the declaration of an inoperable [automatic sequencer] may be delayed:

[ ]

(continued)

(continued)

BASES (continued)

LCO (continued)

The justification for delaying the declaration of [automatic sequencer] inoperability for each of the above items is as follows:

[ ]

AC Sources and Component OPERABILITY

The definition of OPERABILITY states that a component shall be OPERABLE when it is capable of performing its specified functions and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the component to perform its functions are also capable of performing their related support functions. When applying this definition to a component, say an Emergency Core Cooling System (ECCS) pump, the question arises, "How many AC sources are necessary for the pump to be considered OPERABLE?" For the electrical power distribution buses to be OPERABLE, they simply have to be fully energized by one of the capable sources accepted in the plant design, within design voltage and frequency tolerances, and within allowable environmental parameters such as temperature and humidity. Similarly, an ECCS pump is OPERABLE if it is powered from such a fully energized and OPERABLE distribution system. Note that for OPERABILITY of both the distribution system and the components, no requirements, beyond at least one of the electrical power sources that was accepted as a part of the plant design, are made on how many electrical power sources are available to power the bus.

Thus, for plant components and distribution buses, zero electrical power sources means the component or bus is inoperable. Fully energized from at least one power source that was accepted as a part of the plant design means the component or bus is OPERABLE (at least from the point of view of needing electrical support). Thus, the principle for component (including electrical bus) OPERABILITY is that a component may be considered OPERABLE if it has electricity at its terminals (and the electricity came from a source that was accepted as a part of the plant design).

(continued)

(continued)

BASES (continued)

LCO (continued)

With this interpretation of component OPERABILITY, the next question that arises is, "How can an ECCS pump that is only powered from an offsite source be considered OPERABLE?" If such a pump does not have electrical support from a DG, it will not be able to function given a DBA and a loss of offsite power. The short answer to this question is that it is not the ECCS pump that was broken in the above scenario. It was a DG that was inoperable. Thus, for operating MODES, this LCO 3.8.1 contains the necessary ACTIONS for an inoperable required AC source (including a DG). Similarly, for shutdown modes, LCO 3.8.2 contains the necessary ACTIONS for an inoperable required AC source under shutdown conditions. Cascading the inoperability of a single AC source (including DG) to every component in the [division] served by the AC source is not necessary. The longer answer to this question requires some additional explanation.

The electrical power systems at nuclear power plants are designed to meet the GDC listed in Appendix A of 10 CFR 50. The AC electrical power system is designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. The OPERABILITY of the power sources are based upon meeting the design basis of the plant. This includes maintaining at least:

a. {VS-BW,CE,W,BWR/4: One [division] ([Division 1 or Division 2])} {VS-BWR/6: Two out of three [divisions]} of the offsite AC and onsite DC power sources and associated distribution systems OPERABLE during accident conditions, assuming a loss of all onsite power and a single failure; and

b. {VS-BW,CE,W,BWR/4: One [division] ([Division 1 or Division 2])} {VS-BWR/6: Two out of three [divisions]} of the onsite AC and DC power sources and associated distribution systems OPERABLE during accident conditions, assuming a loss of all offsite power and a single failure.

See, for example, GDC 17, 33, 34, 35, 38, and 41.

An important corollary to or consequence of the design requirements (a) and (b) above is the following. For a

(continued)

(continued)

BASES (continued)

LCO (continued)

safety-related component to be considered operable, it must have both a source of offsite and onsite power. This is the design basis definition that is shown here in lower case letters and underlined to distinguish it from the actual definition of OPERABLE that is used in the Technical Specifications. This definition of operable is every bit as valid as the design criteria for a nuclear plant. The difference is that a component is OPERABLE if it has at least one AC source; however, it may not be operable. To be operable, the component would have to have both an onsite and offsite AC source.

Let's examine the differences between OPERABLE and operable for the operating MODES of Applicability that are governed by Specification 3.8.1 (and other operating Technical Specifications). For a typical plant, the LCO of Specification 3.8.1 requires a DG and an offsite circuit for each [division]. Thus, as long as the LCO of Specification 3.8.1 is met, all components are both OPERABLE and operable (in terms of the electrical support they require). Furthermore, if three or more AC sources are inoperable, then the plant must enter LCO 3.0.3 and shut down. Therefore, in these two extremes, any difference between OPERABLE and operable becomes irrelevant. If two AC sources are inoperable on the same bus, and if that bus has no other source of power (e.g., a dead bus), then the two definitions also give the same result, and every component in the [division] is inoperable since they have no electrical power. In fact, the only time the difference becomes relevant is when one or two (but with no dead bus) AC sources become inoperable.

Thus, when in the ACTIONS of Specification 3.8.1 for one or two AC sources inoperable, the components in the [divisions] associated with the inoperable AC source(s) are generally OPERABLE but not operable. At this point, the reason for defining OPERABILITY as requiring only one AC source becomes clear. If one uses the design basis definition of operability in place of OPERABILITY, then every component in the [division] would have to be declared not operable upon the loss of a single AC source.

Performing the Required Actions of the TS for each component that requires AC power in a [division] (when the components still have AC power) just because one AC source is

(continued)

(continued)

BASES (continued)

LCO (continued)

inoperable is not necessary. Fix the AC source and leave the components alone.

If we use the definition of <u>operability</u>, then upon the loss of two AC sources in different [divisions] the plant would have to enter LCO 3.0.3 since two entire safety [divisions] of components would be not <u>operable</u>. This would make the 2-, 12-, and 24-hour Completion Times specified in LCO 3.8.1 for two DGs inoperable, one DG and one offsite circuit inoperable, and two offsite circuits inoperable, respectively, irrelevant.

By not cascading the inoperability of a single AC source down to all the components in its safety [division], two things are lost:

a. The Required Actions for an inoperable component in the component LCO; and

b. A message to the component LCO that the component in this [division] is potentially inoperable under certain Design Basis Events.

The loss of (a) is probably not important. Usually, the Required Action is simply to restore the component to OPERABLE status. In this case, it is not the component that is broken, it is the AC source. The AC source will be fixed within its Completion Time, or other remedial actions, such as a plant shutdown, will be taken.

The loss of (b) is important. Most component LCOs do not allow continued plant operation with a complete loss of function. For example, a typical ECCS Specification will allow loss of ECCS function in one [division] for 72 hours but will require a shutdown if all ECCS function is lost. It is clear that if the design basis definition of <u>operability</u> was used, and if a DG in one [division] was out of service coincident with an ECCS pump in another [division], a shutdown would be required by the ECCS Specification since two ECCS pumps would be not <u>operable</u>. However, when the Specification definition of OPERABILITY is used in place of <u>operability</u>, the ECCS Specification shows one pump inoperable with a 72-hour Completion Time, and the AC sources TS would have one DG inoperable with a 72-hour

(continued)

(continued)

BASES (continued)

LCO (continued)

Completion Time. Thus, there appears to be a difficulty if an AC source is out of service in one [division], and a required feature (such as an ECCS pump) is out of service in another [division].

The problem is that this situation (AC source inoperable in one [division], required feature inoperable in another) represents a potential loss of required feature function under some of the conditions set forth in the design basis. By using the TS definition of OPERABILITY, no message is sent to the required feature LCO upon the inoperability of an AC source. To fix this problem, a cross-[division] check is incorporated into this LCO 3.8.1. See Condition B (for offsite source inoperability) and see Condition D (for onsite source inoperability). The purpose of these two conditions is to recognize that when in them, the plant is in a potential loss-of-function situation. The effect of these two Conditions is to reduce the Completion Time for an inoperable AC source to less than 72 hours. See the appropriate ACTIONS discussion for more information.

Another point of view is that, in practice, the design basis requirement for operability is relaxed for brief periods of time (typically 72 hours or less) while in an AC Sources—Operating ACTION statement. If a [Division 1] DG is out of service, all of the components in the safety [division] associated with that DG are not declared inoperable (even though by the strict definition of operability above, they are, in fact, not operable). Instead, the definition of operability is relaxed to that of OPERABILITY, which says that if a component in the [division] that has an out-of-service DG has electricity at its terminals, it is OPERABLE for the purpose of satisfying its component LCO. Thus, the only ACTION that has to be taken is that of the DG LCO. This relaxation of the design basis definition of operability is deemed acceptable because the DG inoperability is only allowed to persist for a limited amount of time (e.g., 72 hours in this case). The net effect of this interpretation is that during the 72 hours, the GDC are not met. The plant could not take a worst-case single failure and still maintain all safety functions with a loss of all offsite AC sources. In other words, we accept the risk of loss of single-failure protection for an event that involves total loss of offsite AC sources for 72 hours.

(continued)

(continued)

BASES (continued)

LCO (continued)

The above discussion holds equally well for the companion Condition of one offsite circuit inoperable (instead of a DG). Thus, the requirement for both an onsite and offsite AC source of power found in the definition of <u>operability</u> is relaxed for 72 hours while in the AC Sources—Operating ACTION statement for one offsite circuit inoperable.

This relaxation of a design basis requirement is only implemented when in an ACTION of Specification 3.8.1. At all other times, the correct design basis interpretation of the "Necessary electrical power" in the definition of <u>operability</u> is that both onsite and offsite AC sources are required for a component to be considered <u>operable</u> and thus meet the design basis requirements.

<u>Separation and Independence of AC Sources</u>

An additional corollary to or consequence of the design requirements in GDC 17 is that 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 onsite diesel generators, the separation and independence is complete. That is, GDC 17 requires,

> "The onsite electric power supplies, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, for redundancy, and testability to perform their safety functions assuming a single failure."

For the offsite AC sources, the separation and independence is to the extent practical. That is, GDC 17 requires,

> "Electric power from the transmission network to the onsite electrical distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) 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."

It is not acceptable to extrapolate from these words in GDC 17 that the offsite circuits are not completely separate and independent and conclude therefore that a single circuit

(continued)

(continued)

BASES (continued)

LCO (continued)

cross-tied between [divisions] meets the GDC 17 requirements for offsite sources. Similarly, if interrupting devices or protective relaying that normally serves to provide electrical independence between the two circuits are inoperable, it is not acceptable to conclude that all offsite circuits are still OPERABLE. In general, the two offsite circuits are to be maintained separate and independent to the same extent as in the plant design.

APPLICABILITY

The AC sources and sequencers are required to be OPERABLE in {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: 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 anticipated operational occurrences (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.

AC power requirements for {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} are covered in Specification 3.8.2, "AC Sources—Shutdown."

A Note has been added to provide clarification that for this LCO, all required [Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} AC electrical sources and [automatic sequencers] shall be treated as an entity with a single Completion Time.

ACTIONS

A.1

Condition A is one required offsite circuit inoperable. The Required Action A.1 is to restore all required AC electrical power sources (offsite circuits and DGs) to OPERABLE status within a Completion Time of 72 hours {VS-BWR/6: for [Division 1 and Division 2] and within [72 hours] for [Division 3]}.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Performance of SR 3.8.1.1 ensures a highly reliable power source and no common cause failure for the remaining required offsite {VS-BW,CE,W,BWR/4: circuit} {VS-BWR/6: circuits}. The OPERABILITY of the remaining required offsite {VS-BW,CE,W,BWR/4: circuit} {VS-BWR/6: circuits} must be verified once within 1 hour and once per 8 hours thereafter until the inoperable offsite circuit is restored to OPERABLE status.

SR 3.8.1.1 is only required when in Condition A. SR 3.8.1.1 is essentially identical to the normal weekly SR of offsite circuits (i.e., SR 3.8.1.4). The only difference is that SR 3.8.1.1 has a shorter Frequency for verification of the OPERABILITY of the remaining required OPERABLE offsite circuit. If a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition F, for two offsite circuits inoperable, is entered.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition A for a period that should not exceed 72 hours {VS-BWR/6: for [Divisions 1 and 2]. The [72-hour] Completion Time for a [Division 3] offsite circuit inoperability is plant specific. Items to be considered in choosing this Completion Time are:

a. Potential light-loading of the [Division 3] DG during the [72-hour] period when the one required offsite circuit for [Division 3] is inoperable; and

b. The safety function of [Division 3].

In particular, the Completion Time for a [Division 3] offsite circuit inoperability shall not exceed 72 hours if [Division 3] systems support other ESF functions in addition to the HPCS function}. 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 {VS-BW,CE,W,BWR/4: circuit} {VS-BWR/6: circuits} and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

The 72-hour {VS-BWR/6: (or 72-hour] for [Division 3])} limit 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. If Required Action A.1 and its associated Completion Time are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

{VS-BW,CE,W: B.1, B.2.1, and B.2.2}
{VS-GE: B.1, and B.2}

{VS-BW,CE,W:
Condition B is no offsite power to one [division] of the onsite Class 1E Power Distribution System AND one or more required support or supported features, or both, inoperable that are associated with the other [division] that has offsite power, or with opposite OPERABLE DC power subsystem(s), or both, OR the turbine-driven auxiliary feedwater pump inoperable.

{VS-W,CE,W:
Note that the OR in Condition B is not an exclusive "or". That is, the OR in Condition B includes Conditions in which:

a. One or more required support or supported features, or both, are inoperable. . .; or

b. A Condition in which the turbine-driven auxiliary feedwater pump is inoperable; or

c. Both (a) and (b) above.}

{VS-BWR/4:
Condition B is no offsite power to one [division] of the onsite Class 1E Power Distribution System AND one or more required support or supported features, or both, inoperable that are associated with the other [division] that has offsite power, or with opposite OPERABLE DC power subsystem(s), or both.}

{VS-BWR/6:
Condition B is no offsite power to one [division] of the onsite Class 1E Power Distribution System AND one or more required support or supported features, or both, inoperable that are associated with the other [divisions] that have

(continued)

BASES (continued)

ACTIONS (continued)

offsite power, or associated with opposite OPERABLE DC power subsystem(s), or both.}

Condition B is a companion Condition to Condition A. That is, it is not possible to be in Condition B without also being in Condition A. [For there to be no offsite power to one [division] of the onsite Class 1E Distribution System, one offsite circuit and any cross-ties to other offsite circuits must be inoperable or not connected.]

The rationale behind Condition B comes from GDC 33, 34, 35, 38, and 41. They state that,

> "Suitable redundancy in components and features, and suitable interconnections, leakage detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished assuming a single failure."

If, as per the GDC, we assume that all onsite power is not available, then Condition B represents a loss of function for the feature that is inoperable in the other {VS-BW,CE,W,BWR/4: [division] that has} {VS-BWR/6: [divisions] that have} offsite power, or is associated with opposite OPERABLE DC power subsystem(s), or both.

<u>Definition of BX</u>: The allowable time for continued plant operation in Condition B is BX hours. BX is determined as follows. Consult the TS for the required feature that is inoperable. Define BXi as the Completion Time that the inoperable required feature TS allows for a complete loss of all required feature function. If no loss of function is allowed (e.g., if upon the loss of required feature function a shutdown is required), then assign BXi = 0 hours. For each required feature that is inoperable, there will be a BXi. BX is then defined as the minimum of all the BXi; however, if BX is found to be less than 24 hours, BX is reset to 24 hours. If BX is found to be greater than 72 hours, then BX is 72 hours.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

There is one exception to the above rule for finding BX. Usually, 24 hours ≤ BX ≤ 72 hours. However, if the plant is in Condition B and Condition F (two required offsite circuits inoperable) simultaneously, then BX = 12 hours. The rationale for the reduction to 12 hours is that Condition F (two required offsite circuits inoperable) is assigned a Completion Time of 24 hours consistent with Regulatory Guide 1.93 (Ref 4.). However, on a risk basis, Regulatory Guide 1.93 allowed a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety [divisions] of components are OPERABLE. When in Condition B and F simultaneously, this is not the case, and a shorter Completion Time of BX = 12 hours is appropriate.

BX as defined above is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown. (The above addresses the potential for loss of function under certain Conditions postulated in the design basis. In the event of an actual loss of function, the TS covering that loss of function will control the Completion Time.)

The specific list of "required support and supported features" encompassed by Condition B is provided in Reference 5. Required features are those that are designed with functionally redundant safety-related [divisions]. If a plant has a required feature that has no functionally redundant counterpart, that feature may not be required to be included. This is unlikely, however, since single-failure considerations usually require functional redundancy of safety features. Since the Completion Time allowance for this Required Action is limited to 72 hours, those systems with allowed Completion Times ≥ 72 hours for complete loss of function are not included as required features to be checked.

The reason that Condition B is for no offsite power to one [division] of the onsite Class 1E Distribution System is because losing one offsite circuit may not necessarily result in the total loss of offsite power to the [division] because of possible cross-ties to other offsite circuits. No offsite power source to one [division] needs to be established before the determination can be made whether an

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

inoperable redundant feature in the other [divisions] would result in a potential loss of function.

{VS-BW,CE,W:
Auxiliary feedwater is provided by a [50%]-capacity motor-driven feedwater pump in [Division 1], a [50%]-capacity motor-driven feedwater pump in [Division 2], and a [100%]-capacity turbine-driven feedwater pump. Therefore, assuming that all onsite power is not available (as per the GDC), Condition B reduces the 72-hour Completion Time to BX hours (see above for definition of BX) for the case in which auxiliary feedwater function has been reduced to only [50%] of capacity or less.}

{VS-BW,CE,W:
The turbine-driven auxiliary feedwater pump is not included with the "one or more required support or supported features, or both, inoperable that are associated with the other [division] that has offsite power," because the feedwater pump is steam driven (as opposed to motor driven), and thus is not "associated" with either [division] of the AC electrical power sources.}

{VS-BW,CE,W:
The Note for Required Action B.2.2 states, "Required Action B.2.2 is only required in MODES 1, 2, and 3, and in MODE 4 when auxiliary feedwater is being used for plant shutdown and startup." This Note is consistent with the Applicability requirements of Specification 3.7.4, "Auxiliary Feedwater System." When the pressure is < 715 psig] the turbine-driven auxiliary feedwater pump need not be capable of meeting the SR limits of SR 3.7.4.2 on developed head to satisfy the OPERABILITY requirements of Required Action B.2.2. The pump must be capable of coming up to speed and delivering flow, however. Furthermore, the licensee shall verify that the pump passed its last SR 3.7.4.2.}

Operation may continue in Condition B for a period that should not exceed BX hours. In this condition, the remaining OPERABLE offsite circuit and DGs are adequate to

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

supply electrical power to [Division 1 and Division 2] of the onsite Class 1E Distribution System. The BX-hour limit takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Thus, on a component basis, we may have lost single-failure protection for the required feature's function; however, we have not lost function. Similarly, we take 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. If the Required Actions of Condition B and the associated Completion Times are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

C.1

Condition C is one required DG inoperable. Required Action C.1 is to restore the required AC electrical power sources (offsite circuits and DGs) to OPERABLE status within a Completion Time of 72 hours
{VS-BWR/6: for [Division 1 and Division 2] and within [72 hours] for [Division 3]}.

Performance of SR 3.8.1.2 ensures a highly reliable power supply by checking on the OPERABILITY of the required offsite circuits. SR 3.8.1.2 must be performed once within 1 hour of entering Condition C, and once per 8 hours thereafter. Failing to perform SR 3.8.1.2 on a given circuit results in an inoperable circuit. Similarly, if a circuit fails to pass SR 3.8.1.2, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered to reflect the new plant state.

Performance of SR 3.8.1.3 ensures no common cause failure for the remaining required DG[s]. The determination of no common cause inoperability of the remaining required DG[s] must be made once within [8] hours of entering Condition C. If during the performance of SR 3.8.1.3 common cause is found, or if a required DG fails SR 3.8.1.3 for some other reason, then two required DGs are inoperable and Condition G is entered.

Note 3 of Condition C requires that SR 3.8.1.3 shall be completed if Condition C is entered. The intent is that all DG inoperabilities must be investigated for common cause

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

failures as per SR 3.8.1.3, regardless of how long the DG inoperability persists.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition C for a period that should not exceed 72 hours {VS-BWR/6: for [Divisions 1 and 2]. The [72-hour] Completion Time for a [Division 3] DG inoperability is based upon the risk-significance of the [Division 3] DG in coping with a station blackout (SBO). Calculations show that the core melt frequency increases substantially for an SBO with a [Division 3] DG inoperable for 14 days as compared to an SBO with an OPERABLE [Division 3] DG.

The Completion Time for a [Division 3] DG may be increased from [72 hours] to [14 days] consistent with the HPCS TS provided:

a. The [Division 3] sole function is to support the HPCS function; and

b. Calculations show that the increase in the core melt frequency for an SBO with an inoperable [Division 3] DG is acceptably low.

If other ESF functions are supported by [Division 3], or if calculations show that the increase in core melt frequency for an SBO with an inoperable [Division 3] DG is unacceptably high, then the Completion Time for an inoperable [Division 3] DG shall be [72 hours].}

In Condition C, the remaining OPERABLE DG[s] and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72-hour {VS-BWR/6: (or [72-hour] for [Division 3])} limit 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. If Required Action C.1 and its associated Completion Time are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

{VS-BW,CE,W: D.1, D.2.1, and D.2.2}
{VS-GE: D.1 and D.2}

{VS-BW,CE,W:
Condition D is one required DG inoperable AND one or more required support or supported features, or both, inoperable that are associated with the OPERABLE DG[s], or with an opposite OPERABLE DC power subsystem, or both, OR the turbine-driven auxiliary feedwater pump inoperable.

{VS-BW,CE,W:
Note that the OR in Condition D is not an exclusive "or". That is, the OR in Condition D includes Conditions in which:

a. One or more required support or supported features, or both, are inoperable. . .; or

b. A Condition in which the turbine-driven auxiliary feedwater pump is inoperable; or

c. Both (a) and (b) above.}

{VS-BWR/4:
Condition D is one required DG inoperable AND one or more required support or supported features, or both, inoperable that are associated with the OPERABLE DGs, or with an opposite OPERABLE DC power subsystem, or both.}

{VS-BWR/6:
Condition D is one DG inoperable AND one or more required support or supported features, or both, inoperable that are associated the OPERABLE DGs, or with opposite OPERABLE DC power subsystems, or both.}

Condition D is a companion Condition to Condition C. That is, it is not possible to be in Condition D without also being in Condition C.

The rationale behind Condition D comes from GDC 33, 34, 35, 38, and 41. They state that,

> "Suitable redundancy in components and features, and suitable interconnections, leakage detection, isolation, and containment capabilities shall be

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished assuming a single failure."

If, as per the GDC, we assume that all offsite power is not available, then Condition D represents a loss of function for the feature that is inoperable in the other {VS-BW,CE,W,BWR/4: [division] that has an OPERABLE DG or in the opposite OPERABLE DC power subsystem, or both.} {VS-BWR/6: [divisions] that have OPERABLE DGs or in opposite OPERABLE DC power subsystems, or both.}

Definition of DX: The allowable time for continued plant operation in Condition D is DX hours. DX is determined as follows. Consult the TS for the required feature that is inoperable. Define DXi as the Completion Time that the inoperable required feature TS allows for a complete loss of all required feature function. If no loss of function is allowed (e.g., if upon the loss of required feature function a shutdown is required), then assign DXi = 0 hours.

For each required feature that is inoperable, there will be a DXi. DX is then defined as the minimum of all the DXi; however, if DX is found to be less than 2 hours, DX is reset to 2 hours. If DX is found to be greater than 72 hours, then DX is 72 hours.

DX as defined above is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown. (The above addresses the potential for loss of function under certain Conditions postulated in the design basis. In the event of an actual loss of function, the TS covering that loss of function will control the Completion Time.)

The specific list of "required support and supported features" encompassed by Condition D is provided in Reference 5. Required features are those that are designed with functionally redundant safety-related [divisions]. If a plant has a required feature that has no functionally redundant counterpart, that feature may not be required to be included. This is unlikely, however, since single-

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

failure considerations usually require functional redundancy of safety features. Since the Completion Time allowance for this Required Action is limited to 72 hours, those systems with allowed Completion Times ≥ 72 hours for complete loss of function are not included as required features to be checked.

{VS-BW,CE,W:
Auxiliary feedwater is provided by a [50%]-capacity motor-driven feedwater pump in [Division 1], a [50%]-capacity motor-driven feedwater pump in [Division 2], and a [100%]-capacity turbine-driven feedwater pump. Therefore, assuming that all offsite power is not available (as per the GDC), Condition D reduces the 72-hour Completion Time to DX hours for the case in which auxiliary feedwater function has been reduced to only [50%] of capacity or less.}

{VS-BW,CE,W:
The turbine-driven auxiliary feedwater pump is not included with the "one or more required support or supported features, or both, inoperable that are associated with the other [division] that has an OPERABLE DG" because the feedwater pump is steam driven (as opposed to motor driven), and thus is not "associated" with either [division] of the AC electrical power sources.}

{VS-BW,CE,W:
The Note for Required Action D.2.2 states, "Required Action D.2.2 is only required in MODES 1, 2, and 3, and in MODE 4 when auxiliary feedwater is being used for plant shutdown and startup." This Note is consistent with the Applicability requirements of Specification 3.7.4, "Auxiliary Feedwater System." When the pressure is < [715 psig] the turbine-driven auxiliary feedwater pump need not be capable of meeting the SR limits of SR 3.7.4.2 on developed head to satisfy the OPERABILITY requirements of Required Action D.2.2. The pump must be capable of coming up to speed and delivering flow, however. Furthermore, the licensee shall verify that the pump passed its last SR 3.7.4.2.}

Operation may continue in Condition D for a period that should not exceed DX hours. In this Condition, the remaining OPERABLE DG[s] and offsite circuits are adequate

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

to supply electrical power to the onsite Class 1E Distribution System. The DX-hour limit takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Thus, on a component basis, we may have lost single-failure protection for the required feature's function; however, we have not lost function. Similarly, we take 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. If the Required Actions of Condition D and the associated Completion Times are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

E.1 and E.2

Condition E is one required offsite circuit inoperable AND one required DG inoperable. The Required Action is to either restore all required offsite circuits to OPERABLE status within a Completion Time of 12 hours OR restore all required DGs to OPERABLE status within a Completion Time of 12 hours. Condition E has been modified by a Note to indicate that when Condition E is entered with no AC source to one [division], LCO 3.8.7 must be immediately entered. Pursuant to the definition of OPERABILITY, this action should have already taken place; however, it is noted here to indicate that the Completion Time for Condition E under this situation is governed by the Completion Time of Required Action A.1 of LCO 3.8.7.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition E for a period that should not exceed 12 hours. The alternative Completion Time is for the situation in which Condition E was entered with no AC power to one [division], and the Completion Time to restore all required offsite circuits or DGs is then governed by LCO 3.8.7.

In Condition E, 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 F (loss of both required offsite circuits). This difference in reliability is offset by the

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

susceptibility of this power system configuration to a single bus or switching failure. The 12-hour or the alternate Completion Time limit 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. If Required Action E.1 and Required Action E.2 and their associated Completion Times are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

F.1

Condition F is two required offsite circuits inoperable. Required Action F.1 is to restore at least
{VS-BW,CE,W,BWR/4: [one]}
{VS-BWR/6: two} required offsite
{VS-BW,CE,W,BWR/4: circuit[s]}
{VS-BWR/6: circuits} to OPERABLE status.
The intent of this Required Action is to restore either all required offsite circuits, or all but one required offsite circuit, to OPERABLE status within a Completion Time of 24 hours.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition F for a period that should not exceed 24 hours. This degradation level 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 source have not been degraded. This degradation level generally corresponds to a total loss of the immediately accessible offsite power sources.

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

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

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 design basis transient or accident. 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 limit provides a period of time to effect restoration of all or all but one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

Per Reference 4, with the available offsite AC source 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 may continue for a total time that should not exceed 72 hours (consistent with the loss of one AC source).

If no offsite source is restored within the first 24-hour period of continued operation, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

<u>G.1</u>

Condition G is two required DGs inoperable. Required Action G.1 is to restore at least {VS-BW,CE,W,BWR/4: [one]} {VS-BWR/6: two} required diesel {VS-BW,CE,W,BWR/4: generator[s]} {VS-BWR/6: generators} to OPERABLE status.

The intent of this Required Action is to restore either all required DGs, or all but one required DG, to OPERABLE status within a Completion Time of 2 hours.

With two DGs inoperable, there are no remaining standby AC sources. 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

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

electrical power system is the only source of AC power for 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.

Per Reference 4, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. If both DGs are restored within 2 hours, unrestricted operation may continue. If only one DG is restored within these 2 hours, operation may continue for a total time that should not exceed 72 hours (consistent with the loss of one AC source). If no DG is restored within the first 2 hours of continued operation, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

H.1

Condition H is three required AC sources inoperable. The Required Action is to enter LCO 3.0.3 immediately.

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 Surveil will cause a loss of function. Therefore, no additional time is justified for continued operation. The plant should be brought promptly to a controlled shutdown as required by LCO 3.0.3. During the shutdown process, the AC electrical power system should be critically monitored, and necessary actions taken, such as cross-connecting a supply to a load, if required, to ensure a safe shutdown.

I.1

Condition I is one required [automatic load sequencer] inoperable. The Required Action is to restore all required [automatic load sequencers] to OPERABLE status within the Completion Time of [2] hours [for Divisions 1 and 2].

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

{VS-BWR/6: If the sequencer is associated with [Division 3], then the Completion Time is [2 hours].}

{VS-BWR/6: [The [2-hour] Completion Time for an inoperable [Division 3] [automatic sequencer] is plant specific. Items to be considered in specifying this Completion Time for a given facility include:

a. The safety function of [Division 3]. If [Division 3] supports only the HPCS function, then there may not even be a [Division 3] [automatic sequencer] because there is only one large load to be connected to the [Division 3] ESF bus. If other ESF functions are supported by [Division 3], then the Completion Time for an inoperable [Division 3] [automatic sequencer] shall be [2 hours]; and

b. The safety function of the [Division 3] [automatic sequencer]:

   1. What is its role in mitigating a DBA?

   2. Does the [Division 3] [automatic sequencer] function as a support system to the [Division 3] DG, [Division 3] offsite circuit, or both? What ESF functions does it support?

   3. What is the role of the [Division 3] [automatic sequencer] in mitigating an SBO?}

Condition I corresponds to the sequencer(s) for [one ESF bus] being inoperable. If the sequencer(s) to [more than one ESF bus] are inoperable, enter LCO 3.0.3.

The sequencer(s) is (are) an essential support system to [both the offsite circuit and the DG associated with a given ESF bus.] [Furthermore, the sequencer 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 [2]-hour Completion Time for [Divisions 1 and 2] {VS-BWR/6: and [2-hour] Completion Time for [Division 3]} provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

the probability of an accident (requiring sequencer OPERABILITY) occurring during periods where the sequencer is inoperable is minimal.

[For plants that can show that the sequencer's role is less vital, a longer Completion Time may be appropriate. For example, if the ESF loads are block-loaded onto the offsite circuit so that no sequencer operation is required, then it may be possible to show that the sequencer is solely linked to DG OPERABILITY. In such a case, a Completion Time of [72 hours] may be appropriate.]

When a sequencer is inoperable, the associated [ESF bus] is declared inoperable, and LCO 3.8.7 is immediately entered. In LCO 3.8.7 it is determined whether the loss of functional capability exists by verifying whether one or more support or supported features, or both, are inoperable that are associated with the other ESF buses.

J.1 and J.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable AC electrical power sources and sequencers cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6 hours} {VS-GE: 12 hours} and in {VS-BW,CE,W: MODE 5} {VS-GE: MODE 4} within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The AC source are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with GDC 18 (Ref. 6). 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, "Selection, Design, and Qualification of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Power Plants" (Ref. 2); Regulatory Guide 1.108, "Periodic Testing of DG Units Used as Onsite Electric Power Systems at Nuclear Power Plants" (Ref. 7); and Regulatory Guide 1.137, "Fuel Oil Systems for Standby DGs" (Ref. 8), as addressed in the FSAR.

SR 3.8.1.1

This SR is required only when in Condition A, "One offsite circuit inoperable." Upon the inoperability of an offsite circuit, any remaining required offsite circuits that are OPERABLE must be checked for OPERABILITY within 1 hour of entering Condition A and once per 8 hours thereafter. If additional offsite circuits are found inoperable, they must be declared inoperable, and the corresponding Conditions of LCO 3.8.1 must be entered.

The requirement to perform SR 3.8.1.1 continues until LCO 3.8.1 is met, or until the plant is put in a MODE of operation outside of the Applicability of LCO 3.8.1.

This SR assures proper circuit continuity for the offsite AC power supply to the onsite distribution network and availability of offsite AC power. The breaker alignment verifies that each breaker is in its correct position to ensure distribution buses and loads are connected to their preferred power source. The check on devices that provide the separation and independence assures that protective relaying and interrupting devices are OPERABLE so that circuit independence can be maintained.

This Surveillance Frequency is justified based on the necessity to maintain a reliable AC electrical power system. The Frequency of 1 hour and once per 8 hours thereafter takes into account the time required to perform the Surveillance and the difficulty in completion. This is balanced against the desirability of having accurate and reliable information about remaining sources of offsite power upon the inoperability of one of the other offsite sources. Also, these Frequencies take into account the capacity, capability, redundancy, and diversity of the AC sources; other indications available in the control room, including alarms, to alert the operator to AC sources malfunctions; and the low probability of a DBA occurring during this period.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

It is recognized that an operator could choose not to perform SR 3.8.1.1 within 1 hour and once per 8 hours thereafter. Instead the operator could simply declare the second offsite circuit inoperable and accept a shorter Completion Time. While such action would be within the strict legal interpretation of the TS, it would not normally be prudent. In general, the operator should welcome the latest information on the condition of the plant. Furthermore, by failing to perform the SR on the second circuit, information on common cause failure may go undiscovered.

SR 3.8.1.2

This SR is required only when in Condition C, one DG inoperable. Upon the inoperability of a DG, any required offsite circuits that are OPERABLE must be checked for OPERABILITY within 1 hour of entering Condition C and once per 8 hours thereafter. If offsite circuit(s) are found inoperable, they must be declared inoperable, and the corresponding Conditions of LCO 3.8.1 must be entered.

The requirement to perform SR 3.8.1.2 continues until LCO 3.8.1 is met, or until the plant is put in a MODE of operation outside of the Applicability of LCO 3.8.1.

This SR assures 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 distribution buses and loads are connected to their preferred power source. The check on devices that provide the separation and independence assures that protective relaying and interrupting devices are OPERABLE so that circuit independence can be maintained.

This Surveillance Frequency is justified based on the necessity to maintain a reliable AC electrical power system. The Frequency of 1 hour and once per 8 eight hours thereafter takes into account the time required to perform the Surveillance and the difficulty in completion. This is balanced against the desirability of having accurate and reliable information about remaining sources of offsite electrical power upon the inoperability of one of the other offsite sources. Also these Frequencies take into account

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

the capacity, capability, redundancy and diversity of the AC sources; other indications available in the control room, including alarms, to alert the operators to AC sources malfunctions; and the low probability of a DBA occurring during this period.

It is recognized that an operator could choose not to perform SR 3.8.1.2 within 1 hour and once per 8 hours thereafter. Instead the operator could simply declare the offsite circuit inoperable and accept a shorter Completion Time. While such action would be within the strict legal interpretation of the TS, it would not normally be prudent. In general, the operator should welcome the latest information on the condition of the plant. Furthermore, by failing to perform the SR on the offsite circuit(s), information on common cause failure may go undiscovered.

SR 3.8.1.3

This SR is only required when in Condition C, one DG inoperable. Each and every required DG inoperability must be evaluated for common cause failure potential by performance of SR 3.8.1.3, regardless of when the DG is returned to OPERABLE status. If additional DGs are found inoperable, they must be declared inoperable, and the corresponding Conditions of LCO 3.8.1 must be entered.

The purpose of this SR is to determine absence of common cause for the DG inoperability for any remaining required DGs that are OPERABLE. This can be done either by analysis and reasoning (item A.1 of SR 3.8.1.3) or by starting the DG(s) that are OPERABLE (item B.1 of SR 3.8.1.3).

This Surveillance Frequency is justified based on the necessity to maintain a reliable AC electrical power system. The Frequency of once within [8] hours of entering Condition C takes into account the time required to perform the Surveillance and the difficulty in completion. This is balanced against the desirability of having accurate and reliable information about remaining sources of onsite electrical power upon the inoperability of one of the other onsite sources. Also these Frequencies take into account the capacity, capability, redundancy, and diversity of the AC sources; other indications available in the control room,

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

to alert the operators to AC sources malfunctions; and the low probability of a DBA occurring during this period.

SR 3.8.1.4

This SR assures 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 distribution buses and loads are connected to their preferred power source. The check on devices that provide the separation and independence assures that protective relaying and interrupting devices are OPERABLE so that circuit independence can be maintained. The 7-day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and its status is displayed in the control room.

SR 3.8.1.5 and SR 3.8.1.17

These SRs help to ensure the availability of the standby electrical power supply to mitigate design basis transients and accidents and maintain the plant 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 a Note to indicate that all DG starts for these Surveillances may be preceded by an engine prelubricating period in accordance with vendor recommendations. For the purposes of this testing, the DGs shall be started from standby conditions.

Standby conditions for a [Division 1 or 2] DG means the diesel engine coolant and oil are being continuously circulated and temperature maintained consistent with manufacturer recommendations.
{VS-BWR/6: Standby conditions for [Division 3] DG means the lubricating 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.}

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

All engine starts for SR 3.8.1.5 may be preceded by warmup procedures as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine are minimized. This is the intent of Note 3 of SR 3.8.1.5.

SR 3.8.1.5 has been modified by a fourth Note, Note 4, requiring the performance of SR 3.8.1.6 immediately after SR 3.8.1.5. The exceptions (a) and (b) are for cases in which less than a full complement of AC sources, may be available. Therefore, the performance of SR 3.8.1.6 is not required because it requires the paralleling of two of the remaining AC sources, which may compromise the AC source independence.

SR 3.8.1.17 requires that, on a 184-day Frequency, the DG start from standby conditions and achieve required voltage and frequency within 10 seconds. The 10-second requirement supports the assumptions in the design basis LOCA analysis (Ref. 9). The 10-second start requirement may not be applicable to SR 3.8.1.5 (see Note 3 of SR 3.8.1.5), which is usually performed on a 31-day Frequency. Since SR 3.8.1.17 does require a 10-second start, it is more restrictive than SR 3.8.1.5, and it may be performed in lieu of SR 3.8.1.5. This is the intent of Note 1 of SR 3.8.1.5. The normal 31-day Frequency for SR 3.8.1.5 (see DG test schedule, Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 2). The 184-day Frequency for SR 3.8.1.17 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 10). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.17 has been modified by a second Note, Note 2, which requires, following the completion of SR 3.8.1.17, the performance of SR 3.8.1.6. An exception is when SR 3.8.1.17 is required by SR 3.8.2.1. In this situation, less than a full complement of AC sources may be available. Therefore, the performance of SR 3.8.1.6 is not required because it requires the paralleling of two of the remaining AC sources, which may compromise the AC source independence.

<u>SR 3.8.1.6</u>

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

equivalent of the maximum expected accident loads. A third Note to this SR, Note 3, indicates that this Surveillance should only be conducted on one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. A minimum run time of 60 minutes is required to stabilize engine temperatures. Actual run time should be in accordance with vendor recommendations with regard to good operating practice and should be sufficient to ensure that cooling and lubrication are adequate for extended periods of operation, while minimizing the time that the DG is connected to the offsite source.

In order to assure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing shall be performed using a power factor in the range: [0.8] ≤ power factor ≤ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design inductive loading.

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 (Ref. 10).

Note 2 modifies this Surveillance by stating that momentary transients because of 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.

The normal 31-day Frequency for this Surveillance (see DG test schedule, Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 2).

SR 3.8.1.7

This Surveillance verifies that, without the aid of the refill compressor, sufficient air-start capacity for each DG

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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. If the pressure is less than the value specified in this SR, the DG shall be declared inoperable. The five-start-cycles requirement is intended to provide redundancy for the DG start capability in the event that the hot DG does not start on the first attempt.

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 3.8.1.8

This SR provides verification that each DG day [and engine-mounted fuel] tank contains enough fuel oil, measured from the low-level alarm setpoint, to operate the DG for at least 1 hour at full load. If the day [and engine-mounted fuel] tank level is less than the required limit, the DG is inoperable.

The 31-day Frequency is adequate to ensure 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 3.8.1.9

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 facility in a safe shutdown condition and to bring in replenishment fuel from an offsite location. If the storage tank level is less than the required limit, the DG is inoperable.

The 31-day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low-level alarms are

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.10

This Surveillance ensures that sufficient lubricating 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 diesel. Implicit in this SR is the requirement to verify the capability to transfer the lubricating-oil from its storage location to the DG. If it can be demonstrated that the DG lubricating-oil sump can hold adequate inventory for 7 days of full-load operation without the level reaching a dangerous point, then the quantity or level of lubricating oil in the sump can be used in this SR. If the lubricating oil inventory is less than the limit, the DG is inoperable.

A 31-day Frequency is adequate to ensure that a sufficient lubricating-oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.

SR 3.8.1.11

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/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. The tests, limits, and applicable American Society for Testing Materials (ASTM) standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4054-[ ];

b. Verify in accordance with the tests specified in ASTM D975-[ ] that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83° but ≤ 0.89° or an API gravity at 60°F of ≥ 27° but ≤ 39°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes but ≤ 4.1 centistokes, and a flash point ≥ 125°F; and

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-[ ].

These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case shall the time between receipt of new fuel and conducting the tests exceed 31 days.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not constitute a DG OPERABILITY concern since the fuel oil is not added to the storage tanks.

SR 3.8.1.12

Within 31 days following the initial new fuel-oil sample, this Surveillance is performed to establish that the other properties specified in Table 1 of ASTM D975-[ ] are met for new fuel oil when tested in accordance with ASTM D975-[ ], except that the analysis for sulfur may be performed in accordance with ASTM D1522-[ ] or ASTM D2622-[ ]. The 31-day period is acceptable because the fuel-oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. For the same reason, should one or more of these properties not be within limits, there is no need to declare the DG inoperable. It is acceptable to continue operation for up to [31] days while measures are taken to ensure that the properties of the mixed fuel oil are within limits or that the fuel-oil properties are being restored to within limits. If after continued operation for [31] days the properties of the mixed fuel oil are still not within limits, the DG shall be declared inoperable.

SR 3.8.1.13

This Surveillance is an integral part of a comprehensive program to ensure the availability of high-quality fuel oil for the DGs at all times. By testing for particulate on a 31-day basis, information regarding the condition of stored fuel oil can be obtained and trended.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Fuel-oil degradation during long-term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel-oil injection equipment, however, which can cause engine failure. If particulate is removed from stored fuel oil by circulating the oil through filters (other than diesel engine filters), the fuel oil can be restored to acceptable condition and its storage life extended indefinitely. By obtaining and trending particulate data, it is possible to determine when stored-fuel-oil cleanup will be necessary. This is done before the maximum allowable particulate concentration is reached.

Particulate concentrations should be determined in accordance with ASTM D2276-[ ], Method A. 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 lab testing in lieu of field testing. In the case(s) where the total stored-fuel-oil volume 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 that indicate that particulate concentration is unlikely to change between Frequency intervals.

There is no quantitative data regarding the capability of diesel engines to operate for prolonged periods of time with fuel-oil particulate concentrations in excess of 10 mg/l. Therefore, if this limit is reached, the associated DG shall be declared inoperable. In practice, however, this should not present a problem since the concept behind this SR is to establish fuel-oil degradation trends, which will provide an alert to the need for corrective action prior to impacting on DG OPERABILITY.

SR 3.8.1.14 and SR 3.8.1.15

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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

fuel-oil day [and engine-mounted] tanks and from storage tanks once every 31 days will eliminate the necessary environment for survival. This is the most effective means of controlling microbiological fouling. In addition, it will eliminate 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 will minimize fouling as well as provide data regarding the watertight integrity of the fuel-oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 8).

SR 3.8.1.16

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. This is required to support the 7-day continuous operation of standby power sources. This Surveillance provides assurance that the fuel-oil transfer pump is OPERABLE, the fuel-oil piping 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 Section XI code; however, the design of fuel-transfer systems is such that pumps will 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. Upon failure of this SR, the DG shall be declared inoperable immediately.

SR 3.8.1.17

See SR 3.8.1.5.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

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 has been modified by a Note, Note 1, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 2 has been included in this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.19

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. [For this facility, the largest single load for each DG and its horsepower rating is as follows:] As required by IEEE-308, 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 this facility, the SR 3.8.1.19

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

frequency ([63] Hz) for each DG and one of the two above criteria used to arrive at this number are as follows:]

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 2) recommendations for response during load sequence intervals. The [3] seconds specified is equal to 60% of a typical 5-second interval. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.19a corresponds to the maximum frequency excursion, while SR 3.8.1.19b and SR 3.8.1.19c are steady-state voltage and frequency values that the system must recover to following load rejection. The [18-month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 7).

In order to assure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing shall be performed using a power factor in the range: [0.8] ≤ power factor ≤ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading. If the facility uses the actual single largest load to perform this test, then the power factor will be set by that load.

This SR has been modified by a Note, Note 1, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.20

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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

may occur because of a system fault or inadvertent breaker tripping. This Surveillance verifies proper engine-generator load response under the simulated test conditions. This test will simulate the loss of the total connected load that the DG will experience following a full-load rejection and verify that the DG will not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and continue to be available, this response will assure 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 assure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing shall be performed using a power factor in the range: [0.8] ≤ power factor ≤ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading.

This SR has been modified by a Note, Note 1, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbation to the electrical distribution systems that could result in a challenge to continued steady-state operation.

The [18-month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 7) and is intended to be consistent with expected fuel-cycle lengths.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.21

As required by Regulatory Guide 1.108 (Ref. 7), 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

from the loss of offsite power, including shedding of the non-essential 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 automatic start time of [10] seconds is derived from requirements of the accident analysis to respond to a design basis large-break LOCA. The minimum steady-state output voltage of [3744] V is [90%] of the nominal [4160 V] output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% of 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 nameplate rating.

The specified maximum steady-state output voltage of 4576 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 will be no more than the maximum rated operating voltages.

The specified minimum and maximum steady-state output frequency of the DG is [58.8] Hz and [61.2] Hz respectively. This is equal to ± 2% of the 60 Hz nominal frequency and is derived form the recommendations given in Regulatory Guide 1.9 (Ref. 2) that the frequency should be restored to within 2% of nominal following a load sequence step. 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 Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(1), 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, Note 1, stating that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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. {VS-BWR/6: For the [Division 3] DG, standby conditions means the lubricating 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}.

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.22

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 ≥ [5] minutes. The [5]-minute period provides sufficient time to demonstrate stability. SR 3.8.1.22d and SR 3.8.1.22e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a ESF signal without loss of offsite power. The bases for the time, voltage, and frequency tolerances specified in this Surveillance are discussed under SR 3.8.1.21, above.

This SR has been modified by a Note, Note 1, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall 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. {VS-BWR-6: For the [Division 3] DG, standby conditions means the lubricating oil is heated and continuously circulated

(continued)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

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 means of natural circulation).

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

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

SR 3.8.1.23

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 ESF actuation test signal and critical protective functions (engine overspeed, generator differential current, and low lubricating 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 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

performed on the [18-month] Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR has been modified by a Note, Note 1, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required DG from service.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

<u>SR 3.8.1.24</u>

Regulatory Guide 1.108 (Ref. 7), 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 the 2-hour rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.5, and for gradual loading, discussed in SR 3.8.1.6, are applicable to this SR.

In order to assure that the DG is tested under load conditions that are as close to design conditions as possible, testing shall be performed u... power factor in the range: [0.8] ≤ power factor ≤ [0.. ...his power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading.

The [18-month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), 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.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

This Surveillance has been modified by a Note, Note 1, which 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.

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.25

This Surveillance demonstrates that the diesel engine can restart from a hot condition 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 requirement that the diesel have operated for at least 2 hours at full-load conditions prior to performance of this Surveillance is based on manufacturer's recommendations for achieving hot conditions. The bases for the voltage and frequency tolerances are discussed in the Bases for SR 3.8.1.21.

The Surveillance demonstrates the DG capability to respond to accident signal while hot, such as subsequent to shutdown from normal Surveillances. The [18-month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(5).

In order to assure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing shall be performed using a power factor in the range: [0.8] $\leq$ power factor $\leq$ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading.

This SR has been modified by a Note, Note 1, which states that the SR shall be performed within 5 minutes of shutting down the DG after it has operated more than 2 hours at between [5450 and 5740] kW. This is to ensure that the test is performed with the diesel sufficiently hot.

This SR has been modified by a second Note, Note 2, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturers. The reason for this is to minimize wear and tear on the diesel during testing.

This Surveillance has been modified by a third Note, Note 3, which states that momentary transients due to changing bus loads do no invalidate this test. 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.

SR 3.6.1.26

As required by Regulatory Guide 1.108 (Ref.7), paragraph 2.a.(6), this Surveillance assures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and 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 and 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. 7), paragraph 2.1.(6), and takes into consideration plant conditions required to perform the Surveillance.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

This SR has been modified by a Note, Note 1, which states that the SR must not performed in {VS-BW,CE,W: MODE 1, 2, 3, OR 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.27

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if a LOCA actuation 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. 11), paragraph 6.2.6(2).

The [18-month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), 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, Note 1, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2 or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.28

As required by Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(2), each DG is required to demonstrate proper operation for the DBA loading sequence to ensure that voltage and frequency are maintained within the required limits. Under

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

accident conditions, prior to connecting the diesel generators to their appropriate bus, all loads are shed except load center feeders and those motor control centers that power Class 1E loads (referred to as "permanently connected" loads). Upon reaching rated voltage and frequency, the DGs are then connected to their respective bus. Loads are then sequentially connected to the bus by the [automatic load sequencer]. 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 3 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. 7), 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 has been modified by a Note, Note 1, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

<u>SR 3.8.1.29</u>

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). SR 3.8.1.29b and SR 3.8.1.29c ensure that permanently connected loads remain energized from the offsite electrical power system, and that emergency loads are energized [or auto-connected through the load sequencer] to the offsite electrical power system. Before the last [sequencer] load step, a loss of offsite power is simulated. It must then be shown that the AC

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

sources and sequencer reset themselves so that the powering of the loads can begin all over again, this time with the DG as the power source.

This SR has been modified by a Note, Note 1, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall 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. {VS-BWR/6: For the [Division 3] DG, standby conditions means the lubricating 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 circulation.}

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

The Frequency of [36 months] alternated with SR 3.8.1.30 means that once within [18 months] either SR 3.8.1.29 or SR 3.8.1.30 is completed for each DG. Then once within the following [18 months] the other SR, SR 3.8.1.30 or SR 3.8.1.29, is completed for each DG. This Frequency 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]. [For this facility, operating experience has demonstrated that the Frequency for this SR is adequate for the following reasons:]

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.30

In the event of 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 under SR 3.8.1.22 above, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal.

The Frequency of [36 months] alternated with SR 3.8.1.29 means that once within [18 months] either SR 3.8.1.29 or SR 3.8.1.30 is completed for each DG. Then once within the following [18 months] the other SR, SR 3.8.1.30 or SR 3.8.1.29, is completed for each DG. This Frequency 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]. For this facility, operating experience has demonstrated that the Frequency for this SR is adequate for the following reasons:]

This SR has been modified by a Note, Note 1, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall 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. {VS-BWR/6: For the [Division 3] DG, standby conditions means the lubricating 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 means of natural circulation}.

This SR has been modified by a second Note, Note 2, which states that the SE must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODF 1, 2, or 3}. The reason for this is that performing the SR would remove a required

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR

SR 3.8.1.31

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. 8), paragraph 2.f. This Sr also requires the performance of the Section XI examinations of the tanks. To preclude the introduction of surfactants in the fuel system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents.

SR 3.8.1.32

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. 7), paragraph 2.b and Regulatory Guide 1.137 (Ref. 8), paragraph C.2.f.

This SF has been modified by a Note that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear on the DG during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. {VS-BWR/6: Standby conditions for [Division 3] DG means the lubricating 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 means of natural circulation.}

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

DG Test Schedule

The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 2). The purpose of this test schedule is to provide sufficiently timely that is test data to establish a confidence level associated with the goal to maintain DG reliability above 0.95 per demand.

Per Regulatory Guide 1.9, Revision 3, each DG unit should be tested at least once every 31 days. Whenever a DG has experienced four or more valid failures in the last 25 demands, the maximum time between tests is reduced to 7 days. Four failures in 25 demands 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, four failures in the last 25 demands may only be a statistically probable distribution of random events. Increasing the test Frequency will allow for 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.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, General Design Criterion 17, "Electric Power Systems."
2. Regulatory Guide 1.9, Rev. [ ], "Selection, Design, and Qualification of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," [date].
3. [Plant Name] FSAR, Tables [8.3-1 to 8.3-3], "[Title]."
4. Regulatory Guide 1.93, Rev. [ ], "Availability of Electric Power Sources," [date].
5. [List of equipment (required features) referred to in Conditions B and D].

(continued)

(continued)

BASES (continued)

REFERENCES (continued)

6. Title 10, Code of Federal Regulations, Part 50, General Design Criterion 18, "inspection and Testing of Electric Power Systems."

7. Regulatory Guide 1.108, Rev. [ ], "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," [ ].

8. Regulatory Guide 1.137, Rev. [ ] "Fuel Oil Systems for Standby Diesel Generators," [date].

9. [[Plant Name] FSAR, Section [ ]], [This reference is to provide the assumptions of the design basis LOCA].

10. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

11. IEEE Standard 308-[ ], "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

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 Specification 3.8.1, "AC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC and DC power sources and associated distribution systems during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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 AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel-handling accident.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other modes of operation, the GDC (Ref. 2), among other requirements, are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to ensure that the plant is operated within its design basis, with regard to AC sources, the requirements established in the TS must be consistent with the GDC related to electrical systems, as well as with other GDC related to safety-related systems, since the AC sources comprise a typical support system.

In general, when the plant is shut down the TS requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE; or

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show that a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when the Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops - MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation - Low Water Level."}} {VS-GE: The OPERABILITY of the two Residual Heat Removal shutdown cooling subsystems is always required in MODE 4, and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications {VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal—Shutdown," and 3.9.8, "Residual Heat Removal—Low Water Level."} Therefore, in these conditions, [Division 1 and 2] AC sources are required to be OPERABLE as support systems.

Furthermore, by application of GDC 34, "Residual Heat Removal," and the design basis definition of <u>operability</u> (See AC Sources and Component OPERABILITY, Bases for

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Specification 3.8.1), it is clear that each RHR pump must be backed up by separate and independent onsite and offsite sources.

Thus, to meet the design basis definition of <u>operability</u> and GDC 34, four AC sources are required when two RHR pumps are required OPERABLE. As discussed above, however, each plant may have put in additional measures to help mitigate the potential consequences of an accident in these operating MODES. For those plants, Specification 3.8.2 is written such that three out of four AC sources will suffice.

The AC sources satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

LCO 3.8.2.a and LCO 3.8.2.b require that one offsite circuit and one diesel generator be OPERABLE (see Bases 3.8.1) and capable of supplying the onsite Class 1E power distribution subsystem of LCO 3.8.8.a. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from the same safety [division] and that all required AC and DC sources, as well as the distribution subsystem itself, will be OPERABLE so that the AC and DC sources and the distribution subsystem will be capable of fully supporting the non-redundant loads.

When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.2.c requires that they be powered by a third separate and independent, readily available AC source. Readily available means that the source can be made OPERABLE and put into operation, if necessary, within a time commensurate with the safety importance of the redundant loads.

{VS-BWR/6: LCO 3.8.2.d requires an offsite circuit to power the high pressure core spray (HPCS) system when it is required to be OPERABLE, or when other loads assigned to the HPCS system [division] are required to be OPERABLE, or both. The requirements set forth in this LCO may need to be restructured depending on the functions required to be accomplished during these modes of operation by the required loads assigned to [Division 3]. [For this facility, the

(continued)

(continued)

BASES (continued)

LCO (continued)

functions associated with the required loads assigned to [Division 3] during these modes of operation are as follows:]

See the Bases of Specification 3.8.1 for additional information on AC source OPERABILITY and AC source support and supported systems.

LCO 3.8.2 specifies the minimum AC sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE:[or moving loads over irradiated fuel in the primary or secondary containment]}. It ensures 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).

As described in the previous section, "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. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted provided the backup system is OPERABLE or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The AC sources comprise a typical support system.

APPLICABILITY

The AC sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or secondary containment]} provide assurance that:

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

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 OPERABLE; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

AC power requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.1, "AC Sources—Operating."

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required AC electrical power sources inoperable, some equipment is not receiving the minimum support it needs. It is, therefore, required to suspend CORE ALTERATIONS, handling of irradiated fuel, {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the postulated events. It is further required to immediately initiate action 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 unit's 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

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

should be completed as quickly as possible in order to minimize the time the unit's safety systems may be without power.

Required Action A.6 verifies that the Required Actions have been initiated for those supported systems declared inoperable as a result of the total loss of power to a power distribution subsystem within the same Completion Time as that specified for Required Action A.5.

This Required Action has been modified by a Note to clarify that Required Action A.6 needs to be executed only when there are no AC power sources to one or more [divisions] of the onsite Class 1E Power Distribution System.

Required Action A.6 ensures that those identified Required Actions associated with supported systems affected by the total loss of power to a [division] of AC and DC power distribution subsystem have been initiated by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.]

[For this facility, the identified support systems' Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 lists 16 SRs from LCO 3.8.1 that are required to be met. Therefore, see the corresponding Bases for Specification 3.8.1 for a discussion of each SR.

REFERENCES

1. [Unit name] FSAR, Section [ ], "[Title]."
2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 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).

{VS-BW,CE,W,BWR/4: The [250/125] Vdc electrical power system consists of two independent and redundant safety-related Class 1E DC electrical power subsystems ([Division 1 and 2]).} {VS-BWR/6: The [250/125] Vdc electrical power system consists of three independent Class 1E DC electrical power subsystems ([Divisions 1, 2, and 3]).} Each subsystem consists of [two] battery banks [(each bank [50%] capacity)], associated battery charger(s), ([one] per bank), and all the associated control equipment and interconnecting cabling. [Additionally there is [one] spare battery charger per subsystem, which provides backup service in the event that the preferred battery charger is out of service. If the spare battery charger is substituted for one of the preferred battery chargers, then the requirements of independence and redundancy between subsystems are maintained.]

During normal operation, the [250/125] Vdc load is 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 load is automatically powered from the station 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. {VS-BWR/6: The [Division 3] DC electrical power

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

subsystem provides DC motive and control power as required for the High Pressure Core Spray System diesel generator (DG) set control and protection, and all [Division 3]-related control.]}

The DC-power distribution system is described in more detail in Bases for Specifications 3.8.7, "Distribution System—Operating," and 3.8.8, "Distribution System—Shutdown."

In the event of loss of all unit AC power, which is beyond the design bases, the DC system is the only electrical power source available to monitor critical plant parameters and operate selected equipment.

Each battery bank of the [Division 1 and 2] DC electrical power subsystem consists of [120] lead-[calcium] cells with a continuous discharge rating of [1650] Ah for [8] hours to [210] Vs at [77]°F. Plant battery operating voltage is [250/125] Vs, and each battery has adequate storage capacity to carry the required load continuously for at least [2] hours and to perform [three] complete cycles of intermittent loads (Ref. 4). Capacity is adequate for loss-of-coolant accident (LOCA) conditions or any other emergency shutdown.

{VS-BWR/6: The [Division 3] DC electrical power subsystem consists of a [125] V, [60]-cell lead-calcium battery with a continuous discharge of [1000] Ah for [8] hours to [105] V at [77]°F; the battery has adequate storage to carry the required load continuously for at least [2] hours and to perform [three] complete cycles of intermittent loads (Ref. 4). Capacity is adequate for LOCA conditions or any other emergency shutdown.}

The battery chargers of [Division 1 and 2] DC electrical power subsystems are rated at [300] amps with 0.5% voltage regulation with an AC-supplied variation of [480 V ± 15%] in voltage and [60 Hz ± 5%] in frequency (Ref. 4).

{VS-BWR/6: The battery charger for [Division 3] DC electrical power subsystem is rated at [150] amps with 0.5% voltage regulation with an AC-supplied variation of [480 V ± 15%] in voltage and [60 Hz ± 5%] in frequency (Ref. 4).}

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

Each [250/125] Vdc 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.

Battery rooms are continuously ventilated in order to prevent accumulation of hydrogen and to maintain design temperature. The ventilation system limits the hydrogen accumulation to less than [1]% of the total of battery room volume (Ref. 4). The threshold of ignition is 4% and maximum hydrogen generation occurs during overcharging.

The batteries for [Division 1 and 2] 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. Battery size is based on [125]% of required capacity and, after selection of an available commercial battery, results in a battery capacity in excess of [150]% of required capacity. The voltage limit is [2.13] V per cell, which corresponds to a total minimum voltage output of [128] V per battery bank (Ref. 4). The criteria for sizing large lead storage batteries are defined in IEEE-485 (Ref. 5).

{VS-BWR/6: The battery for [Division 3] 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. Battery size is based on [125]% of required capacity and, after selection of an available commercial battery, results in a battery capacity in excess of [150]% of required capacity. The voltage limit is [2.13] V per cell, which corresponds to a total minimum voltage output of [128] V per battery bank (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

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)	design minimum charge to its fully charged state within 24 hours while supplying normal steady-state loads (Ref. 4). {VS-BWR/6: 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 transient and accident analyses in the FSAR, [Chapter 6, "Engineered Safety Features"], and [Chapter 15, "Accident Analyses"], assume that ENGINEERED SAFETY FEATURE (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 sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one [division] of the onsite power or offsite AC sources, DC sources, and associated distribution systems 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. DC Sources—Operating satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	As described in the Background section, each [divisional] DC electrical power subsystem consists of [two] battery bank(s), associated battery charger(s) and the corresponding control equipment and interconnecting cabling within the [division].

(continued)

(continued)

BASES (continued)

LCO (continued)

All DC electrical power subsystems 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 Design Basis Accident (DBA). Loss of any [divisional] DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

A DC electrical power subsystem is OPERABLE provided:

a. All of its required battery bank(s) and battery charger(s) are connected to their associated DC bus(es) and are operating; and

b. All of its required battery bank(s) and battery charger(s) are OPERABLE.

Furthermore, for DC subsystems to be OPERABLE, they must be capable of performing their intended functions, have all support systems OPERABLE, and have successfully completed all SRs.

[For this facility, an OPERABLE [divisional] DC electrical power subsystem consists of the following:]

[For this facility, the following support systems are required OPERABLE to ensure [divisional] DC electrical power subsystem OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare DC electrical power subsystems inoperable and their justification are as follows:]

[For this facility, the supported systems affected by the inoperability of a DC electrical power subsystem and the justification for whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES {VS-BW,CE,W: 1, 2, 3, and 4}{VS-GE: 1, 2, and 3} to ensure safe plant operation and to ensure that:

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

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.

DC electrical power requirements for MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} are addressed in the Bases for Specification 3.8.4, "DC Sources—Shutdown."

ACTIONS

A.1 and A.2

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining DC electrical power {VS-BW,CE,W,BWR/4: subsystem has} {VS-BWR/6: subsystems have} the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst-case single failure would, however, result in {VS-BW,CE,W,BWR/4: the complete loss of the [250/125] Vdc electrical power system} {VS-BWR/6: only one DC electrical power subsystem being OPERABLE} with attendant loss of ESF functions, continued power operation should not exceed 2 hours. The 2-hour Completion Time is based on Regulatory Guide 1.93 (Ref. 6) and reflects a reasonable time to assess plant status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, prepare to effect an orderly and safe plant shutdown. {VS-BWR/6: However, if the inoperable DC electrical power subsystem is associated with [Division 3], then continued operation for up to a [2-hour] Completion Time is plant specific and is meant to be the most limiting Completion Time for all systems that a [Division 3] DC electrical power subsystem supports; furthermore, the number chosen for the [2-hour] Completion Time is not to exceed 8 hours if more than two systems are made inoperable because of the [Division 3] DC electrical power subsystem inoperability.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

For example, if the [Division 3] batteries support only the [Division 3] DG, then a Completion Time of [72 hours] would be appropriate, consistent with the Completion Time for an inoperable [Division 3] DG.

If the [Division 3] batteries support both the [Division 3] DG and the [Division 3] offsite circuit, then the Completion Time will be governed by Condition E of Specification 3.8.1.

If the [Division 3] batteries support even more items, such as a [Division 3] sequencer or other [Division 1 and 2] ESF functions, then a [2-hour] Completion Time is appropriate.}

Required Action A.2 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one [division] DC electrical power subsystem have been initiated and within the same Completion Time as that of Required Action A.1.

Required Action A.2 ensures that those identified Required Actions associated with supported systems affected by the inoperability of the [division] DC electrical power subsystem have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.]

[For this facility, the identified supported system Required Actions are as follows:]

B.1

With two {VS-BWR/6: or more} required [divisions of] DC electrical power subsystems inoperable, the plant is in a condition outside the accident analysis as discussed in A.1, above. Therefore, LCO 3.0.3 must be entered immediately.

C.1

With one [division] DC electrical power subsystem inoperable AND one or more required support or supported features, or both, inoperable associated with the OPERABLE [division] of DC electrical power subsystems, or with opposite OPERABLE AC and DC electrical power distribution subsystems, or both,

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the LCOs for the support or supported feature, or for both, take into consideration the loss of function situation, then LCO 3.0.3 may not need to be entered.

D.1 and D.2

If the DC electrical power subsystem cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6} {VS-GE: 12} hours and in MODE {VS-BW,CE,W: 5} {VS-GE: 4} within 36 hours. The Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE {VS-BW,CE,W: 5} {VS-GE: 4} is consistent with the time required in Regulatory Guide 1.93 (Ref. 6).

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR is based on the battery cell parameter values defined in Table 3.8.3-1. 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

Category A defines the normal parameter limit for each designated pilot cell in each battery. The chosen pilot cells are the weakest cells in the battery based on previous test results. These cells are monitored closely as an indication of battery performance.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 7), with the extra 1/4" allowance above the high-water-level indication for

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

operating margin to account for temperatures and charge effects. In addition to this allowance, a footnote to Table 3.8.3-1 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 transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 7) 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 recommendations of IEEE-450 (Ref. 7), which state that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells. Because resistivity decreases and the charging current increases as the temperature of electrolyte increases, in order to maintain a constant cell voltage, IEEE-450 states that if a warmer cell is below 2.13 V its voltage can be corrected by adding 0.003 V for each degree Fahrenheit (0.005 V/°C) that the cell temperature exceeds the average temperature of other cells. Nevertheless, considering that having dissimilar cell temperatures is an undesirable situation, it is not expected that this correction will have to be made. Instead, appropriate plant preventive actions should be established in order to eliminate the possible causes of the temperature differential.

The Category A limit specified for specific gravity for each pilot cell is ≥ [1.200] (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. 7), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings shall be corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), add 1 point (0.001) to the reading; subtract 1 point for each 3°F below 77°F. The specific gravity of the electrolyte in a cell will increase with a loss of water due to electrolysis or evaporation. A Note in Table 3.8.3-1 requires the above-mentioned correction

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 [3 to 7] 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 of the designated pilot cell. This phenomenon is discussed in IEEE-450 (Ref. 7). A footnote to Table 3.8.3-1 allows the float charge current to be used as an alternate to specific gravity following a battery recharge.

Category B

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out because of a degraded condition or for any other reason.

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 ≥ [1.195] (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells ≥ [1.205] (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 will not mask overall degradation of the battery. A Note to Table 3.8.3-1 requires correction of specific gravity for electrolyte temperature and level. This level correction is not required when battery charging current is < [2] amps on float charge.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Category C

Category C defines the allowable values 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 allowable value, the assurance of sufficient capacity described above no longer exists and the battery must be declared inoperable.

The Category C allowable values specified for electrolyte level (above the top of the plates and not overflowing) ensure 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. 7), 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 allowable value of average specific gravity is based on manufacturer's recommendations ($\geq$ [1.195], 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 will not mask overall degradation of the battery. The Notes to Table 3.8.3-1 that apply to Category A specific gravity are also applicable to Category C specific gravity.

The SR to verify Category A cell parameters is consistent with IEEE-450 (Ref. 7), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells. If pilot cells have one or more battery cell parameters not within Category A limits, the electrolyte level and float voltage of the pilot cells should be verified to meet Category C allowable values within 1 hour. This check will provide a quick indication of the status of the remainder of the battery cells. One hour provides sufficient time to inspect the electrolyte level and to

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 allowable values are met provides assurance that, during the time needed to restore the parameters to the Category A and B limits, the battery will still be capable of performing its intended function. A period of 24 hours is allowed to complete the required verification because specific-gravity measurements must be obtained for each connected cell. Taking into consideration 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.

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 allow time to fully restore the battery cell parameters to normal limits, this time is acceptable. When any battery parameter is outside the Category C allowable value 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.

SR 3.8.3.2

Verifying battery terminal voltage while on float charge for the [258/129] V batteries 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 a 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. 7).

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3

This SR is based on the battery cell parameters defined in Table 3.8.3-1. The meaning of these different parameters is explained in SR 3.8.3.1 above. The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 7). 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. This inspection is also consistent with IEEE-450 (Ref. 7), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurred as a consequence of such discharge or overcharge. The steps to follow in case one or more battery cell parameters are not within limits are described above in SR 3.8.3.1.

SR 3.8.3.4

This Surveillance, verification that the average temperature of representative cells is ≥ [60°F], is consistent with a recommendation of IEEE-450 (Ref. 7), which states that the temperature of electrolytes in representative cells should be determined on a quarterly basis. IEEE-450 suggests taking the temperature of every sixth cell.

While higher-than-normal operating temperatures increase battery capacity, increase internal discharge, lower cell voltages for a given charge current, and raise charging current for a given charge voltage, they decrease battery life.

Lower-than-normal temperatures have the opposite effect, acting to inhibit or reduce battery capacity. Normal battery operating temperatures are [60°]F to [90°F], with a recommended operating temperature of [77]°F. This SR ensures that the operating temperatures remain within an acceptable operating range. These limits are based on manufacturer's recommendations.

SR 3.8.3.5

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 shall 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. In addition, consistent with IEEE-450 (Ref. 7), SR 3.8.3.7 and SR 3.8.3.8 require yearly visual inspection, to detect corrosion, and yearly resistance measurements of connections.

SR 3.8.3.6

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.

This SR is consistent with IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

SR 3.8.3.7 and SR 3.8.3.8

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 help 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 connection resistance limits are the same as those stated in SR 3.8.3.5 above.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequencies of 12 months are consistent with IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and inspection of cell-to-cell and terminal connection resistance on a yearly basis.

SR 3.8.3.9

This SR requires that each battery charger be capable of supplying [400] amps and [250/125] V for ≥ [8] hours. These requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 8), 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 ensures that these requirements can be satisfied. This Surveillance is required to be performed during {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} since it would require the DC electrical power subsystem to be inoperable during performance of the test.

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.

SR 3.8.3.10

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 should correspond to the design duty cycle requirements as specified in Reference 4. Reference 4 provides load requirements for DC electrical power subsystems. [Optionally, the design duty-cycle requirements may be defined here].

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 8) and Regulatory Guide 1.129 (Ref. 9), which state that the battery-service test should be performed during refueling

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

operations or at some other outage, with intervals between tests not to exceed 18 months.

A Note to SR 3.8.3.10 allows the once-per-60-months performance of SR 3.8.3.11 in lieu of SR 3.8.3.10. This substitution is acceptable because SR 3.8.3.11 represents a more severe test of battery capacity than SR 3.8.3.10.

This Surveillance is required to be performed during {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} since it would require a DC electrical power subsystem to be inoperable during performance of the test.

SR 3.8.3.11

A battery-performance 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.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 7) and IEEE-485 (Ref. 5). 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 60 months, or every 12 months if the battery shows degradation or has reached 85% of its expected life. Degradation is indicated, according to IEEE-450 (Ref. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is below the manufacturer's rating. An additional SR calls for a performance test on a newly installed battery within 24 months. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 7).

This Surveillance is required to be performed during {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5}, since

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

it would require the DC electrical power subsystem to be inoperable during performance of the test.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 17, "Electric Power System."

2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," U.S. Nuclear Regulatory Commission, March 10, 1971.

3. IEEE-308 [1978], "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations," Institute of Electrical and Electronic Engineers.

4. [Unit Name] FSAR, Section [ ], "[Title]."

5. IEEE-485 [1983], "Recommended Practices for Sizing Large Lead Storage Batteries for Generating Stations and Substations," Institute of Electrical and Electronic Engineers, June 1983.

6. Regulatory Guide 1.93, "Availability of Electric Power Sources," U.S. Nuclear Regulatory Commission, December 1974.

7. IEEE-450 [1987], "IEEE Recommended Practice for Maintenance Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Subsystems," Institute of Electrical and Electronic Engineers.

8. Regulatory Guide 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants," February 1977, U.S. Nuclear Regulatory Commission.

9. Regulatory Guide 1.129, "Maintenance Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Subsystems," U.S. Nuclear Regulatory Commission, December 1974.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources—Shutdown

BASES

BACKGROUND	A description of the DC sources is provided in the Bases for Specification 3.8.3, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC and DC electrical power sources and associated distribution systems during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other Modes of operation (Ref. 2), among other requirements, are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to ensure that the plant is operated within its design basis, with regard to DC sources, the requirements established in the TS must be consistent with the GDC related to electrical systems, as well as other GDC related to safety-related systems, since the DC sources comprise a typical support system.

In general, when the plant is shut down, the TS requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE; or

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show that a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops—MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation—Low Water Level."}} {VS-GE: the OPERABILITY of the two RHR shutdown cooling subsystems is always required in MODE 4 and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications {VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal Shutdown," and 3.9.8, "Residual Heat Removal—Low Water Level."} Therefore, in these conditions, [1 and 2] DC electrical power sources are required to be OPERABLE as support systems.

The DC Sources satisfy Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

LCO 3.8.4.a requires OPERABILITY of the DC electrical power subsystem associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.a. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from the same safety [division] and that all required AC and DC electrical power sources, as well as the power distribution subsystem itself, will be OPERABLE so that the AC and DC electrical power sources and power distribution subsystem will be capable of fully supporting the non-redundant loads.

When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.4.b requires that they receive DC electrical power from the other [division] DC electrical power subsystem associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.b. Therefore, LCO 3.8.4.b requires this other [division] DC electrical power subsystem to be OPERABLE.

{VS-BWR/6: LCO 3.8.4.c requires OPERABILITY of the [division 3] DC electrical power subsystem associated with the onsite Class 1E power distribution subsystem of LCO 3.8.8.c when the High Pressure Core Spray (HPCS) System is required to be OPERABLE, or when other loads assigned to the HPCS system [division] are required to be OPERABLE, or both.}

See the Bases of Specification 3.8.3 for additional information on DC electrical power source OPERABILITY and DC electrical power source support and supported systems.

LCO 3.8.4 specifies the minimum number of DC sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or secondary containment]}. It ensures the availability of sufficient DC electrical 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, inadvertent reactor vessel draindown).

(continued)

(continued)

BASES (continued)

LCO (continued)

As described in the previous section, "Applicable Safety Analyses," in the event of an accident during shutdown, the TS are designed to maintain the plant in such a condition that, even with a single failure, the plant will not be in immediate difficulty. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted, provided the backup system is OPERABLE or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The DC sources comprise a typical support system.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel 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 OPERABLE; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

DC electrical power requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.3, "DC Sources—Operating."

(continued)

BASES (continued)

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required DC electrical power subsystems inoperable, some equipment is not receiving the minimum support it needs. Therefore, it is required to suspend CORE ALTERATIONS, handling of irradiated fuel, {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the 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 unit's 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 the unit's safety systems may be without power.

Required Action A.6 verifies that the Required Actions for supported systems declared inoperable because of the inoperability of one or more DC electrical power subsystems have been initiated and within the same Completion Time as that specified for Required Action A.5.

Required Action A.6 ensures that identified Required Actions associated with supported systems affected by the inoperability of one or more DC electrical power subsystems have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Action for Condition A of this LCO.]

[For this facility, the identified supported systems' Required Actions are as follows:]

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

SR 3.8.4.1 requires performance of all Surveillances required by SR 3.8.3.1 through SR 3.8.3.11. Therefore, see the corresponding Bases for Specification 3.8.3 for a discussion of each SR.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 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 in being powered from the DC battery source. There is [one] inverter per AC vital bus making a total of [four] inverters. The function of the inverter is to convert DC electrical power to AC electrical power, thus providing an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). The inverters are powered from the [120] V battery source. [For this facility, specific background details on inverters, such as type, capacity, operating limits, and number and status of spares, are as follows:] [ ]
APPLICABLE SAFETY ANALYSES	The initial conditions of design basis transient and accident analyses in [the FSAR, Chapter 6, "Engineered Safety Features," and Chapter 15, "Accident Analyses"], assume ESF 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 RPS and ESFAS instrumentation and controls 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 Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 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 plant. This includes maintaining at least one [division] of the onsite or offsite AC electrical power sources, DC electrical power sources, (continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

and associated distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power; and

b. A worst-case single failure.

Inverters satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

The power distribution subsystems listed in Table B 3.8.7-1 include the inverters. Those 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.

The LCO states that the required inverters shall be OPERABLE. The required inverters for [Division 1] are [Plant Specific: . . . fill in the inverter numbers for [Division 1]]. The required inverters for [Division 2] are [Plant Specific: . . . fill in the inverter numbers for [Division 2]].

{VS-BWR/6: [Division 3] inverters that support the High Pressure Core Spray (HPCS) System or both the HPCS System and other systems are required OPERABLE by LCO 3.8.5 if they are needed to ensure the OPERABILITY OF THE HPCS System and the other systems that they support.}

Upon the inoperability of one required inverter, Condition A is entered. Upon the inoperability of two or more required inverters, entry into LCO 3.0.3 is implicitly required.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is not defeated. If one required inverter is inoperable the possibility of a reactor spurious trip is increased. 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.

(continued)

(continued)

BASES (continued)

LCO (continued)

OPERABILITY is met, as it applies to inverters, provided a correct DC voltage ([120] V) is applied, a correct AC voltage is at the output, and these voltages are within the design voltage and frequency tolerances. Furthermore, the inverters must be within the manufacturers specifications for environmental factors such as temperature and humidity.

This LCO is modified by a Note allowing [two] inverters to be disconnected from their associated DC buses for ≤ 24 hours. This allowance is provided to perform an equalizing charge on one battery bank. If the inverters were not disconnected, the resulting voltage condition might damage the inverters energized [from their associated DC buses]. Disconnecting the inverters is allowed provided the associated AC vital buses are energized from their Class 1E constant voltage source transformer and the AC vital buses for other battery banks are energized from the associated inverters connected to their DC buses. 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 taking into consideration the time required to perform an equalizing charge on the battery bank. When utilizing the allowance, if one or more of the provisions is not met (e.g., 24-hour time period exceeded, etc.), LCO 3.0.3 must be entered immediately.

The intent of this Note is to allow only the [one] inverter[s] powered from [its/their] associated DC bus to be disconnected. [Thus, for plants with one battery bank per [division], two inverters may be disconnected. For plants with two battery banks per [division], only one inverter may be disconnected.]

[For this facility, an OPERABLE inverter constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure inverter OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare inverters inoperable and their justification are as follows:]

(continued)

(continued)

BASES (continued)

LCO (continued)

[For this facility, the supported systems affected by the inoperability of an inverter and the justification for whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

The inverters are required to be OPERABLE in {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: 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 {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} are covered in the Bases for Specification 3.8.6.

ACTIONS

<u>A.1, A.2, A.3, and A.4</u>

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. Required Action A.1 allows up to 2 hours to perform this task {VS-BWR/6: <u>OR</u> [2 hours] if a [Division 3] inverter is the inoperable inverter}.

{VS-BWR/6: [The [2-hour] Completion Time for an inoperable [division 3] inverter is plant specific. Items to be considered in specifying this Completion Time for a given facility include:

a. The safety function of [Division 3]. If [Division 3] supports other ESF functions in addition to the HPCS function, then the Completion Time for an inoperable [Division 3] inverter shall be [2 hours]; and

(continued)

(continued)

BASES (continued)

AC [illegible]S (continued)

b. The safety function of the [Division 3] inverter(s):

1. What is its role in mitigating a DBA?

2. What systems does i[illegible] support?

3. What is its role in mitigating a station blackout?]}

The 2-hour Completion Time is consistent with the 2-hour Completion Time for an inoperable DC bus, and an inoperable AC vital bus (see Specification 3.8.7, "Distribution Systems—Operating"). Required Actions A.2 and A.3 allow 24 hours to fix the inoperable inverter and re[illegible]urn it to service (VS-BWR/6: OR [24 hours] if a [division 3] inverter is the inoperable inverter. [The [24-hour] Completion Time is plant specific, and the items listed above should be considered in specifying this time for a given facility]). 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 [illegible] xposed because of the inverter inoperability. Th[illegible] as to be balanced against the risk of an immediate [illegible]tdown, along with the potential challenges to safety systems such a shutdown might 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). Thus, the probability of a spurious reactor trip is increased. Similarly, the uninterruptible, battery-backed, inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices, because the constant voltage t[illegible]nsformer source is more susceptible to voltage drift/degraded voltage than is the inverter source to the AC vital buses.

Required Action A.4 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one inverter have been initiated and within the same Completion Time as that of Required Action A.1.

Required Action A.4 ensures that those identified Required Actions associated with supported systems affected by the inoperability of the inverter have been initiated. This can be accomplished by entering the supported systems' LCOs.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

[Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Action for Condition A of this LCO.]

[For this facility, the identified support systems' Required Actions are as follows:]

B.1

With one required inverter inoperable AND one or more support or supported features, or both, inoperable associated with the other OPERABLE inverters, or with opposite OPERABLE AC and DC electrical power distribution subsystems, or with opposite OPERABLE DC electrical power subsystems, or all three, there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the LCOs of the support or supported feature, or both, take into consideration the loss of function situation, then LCO 3.0.3 may not need to be entered.

C.1 and C.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable devices or components cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6 hours} {VS-GE: 12 hours} and in {VS-BW,CE,W: MODE 5} {VS-GE: MODE 4} within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

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 of the RPS and ESFAS connected to the AC vital buses. The 7-day Frequency takes into account the

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	redundant capability of the inverters and other indications available in the control room that will alert the operator to inverter malfunctions.
REFERENCES	None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Inverters—Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for Specification 3.8.5, "Inverters—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources, DC sources, and inverter sources to each AC vital bus during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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 available to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel-handling accident.

In particular, instrumentation and control capability is powered from the AC vital buses, which are themselves powered by the inverters.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other modes of operation, the GDC (Ref. 2), among other requirements are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to assure that the plant is operated within its design basis, with regard to AC sources, DC sources, and inverters, the requirements established in the TS must be consistent with the GDC related to electrical systems, as well as with other GDC related to safety-related systems, since the AC sources, DC sources, and inverters are typical support systems.

In general, when the plant is shut down, the TS requirements ensure that the plant has the capability to mitigate the

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE, or

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when the Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops—MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation—Low Water Level."} {VS-GE: the OPERABILITY of the two RHR shutdown cooling subsystems is always required in MODE 4, and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications {VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal—Shutdown," and 3.9.8, "Residual

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Heat Removal—Low Water Level.") Therefore, in these conditions, [Division 1 and 2] inverter sources to the AC vital buses are required to be OPERABLE as support systems.

The inverters satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

LCO 3.8.6.a requires OPERABILITY of the inverters associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.a. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from the same safety [division] and that all required AC, DC, and inverter sources, as well as the distribution subsystem itself, will be OPERABLE so that the AC, DC, and inverter sources and the distribution subsystem will be capable of fully supporting the non-redundant loads.

When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.6.b requires that they receive inverter support from the other [division] inverters associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.b. Therefore, LCO 3.8.5.b requires this other [division] inverters to be OPERABLE.

{VS-BWR/6: LCO 3.8.6.c requires OPERABILITY of the [Division 3] inverters associated with the onsite Class 1E power distribution subsystem of LCO 3.8.8.c when the High Pressure Core Spray (HPCS) System is required to be OPERABLE, or when other loads assigned to the HPCS System [division] are required to be OPERABLE, or both.}

See the Bases for Specification 3.8.5 for additional information on inverter OPERABILITY, and inverter support and supported systems.

LCO 3.8.6 specifies the minimum number of inverters required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or secondary containment]}. It ensures the availability of

(continued)

(continued)

BASES (continued)

LCO (continued)

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, inadvertent reactor vessel draindown).

As described in the previous section, "Applicable Safety Analyses," in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition so that even with a single failure, the plant will not be in immediate difficulty. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted provided the backup system is OPERABLE, or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The inverters comprise a typical support system.

APPLICABILITY

The inverters required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel 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 OPERABLE; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

Inverter requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.5, "Inverters—Operating."

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required inverters inoperable, some equipment is not receiving the minimum support it needs. Therefore, it is required to suspend CORE ALTERATIONS, handling of irradiated fuel {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the 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 unit's 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 unit's safety systems may be without power or powered from a constant voltage source transformer.

Required Action A.6 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one or more inverters have been initiated and within the same Completion Time as that specified for Required Action A.5.

Required Action A.6 ensures that identified Required Actions associated with supported systems affected by the inoperability of one or more inverters have been initiated.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.]

[For this facility, the identified supported systems Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

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 of the Reactor Protection System and Engineered Safety Feature Actuation System 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 will alert the operator to inverter malfunctions.

REFERENCES

1. [Unit name] FSAR, Section [ ], "[Title]."
2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems—Operating

BASES

BACKGROUND

{VS-BW,CE,W,BWR/4: The onsite Class 1E AC and DC electrical power distribution system is divided by [division] into [two] redundant and independent AC and DC electrical power distribution subsystems. Each [divisional] AC and DC electrical power distribution subsystem is comprised of [PLANT SPECIFIC: List the major AC, AC vital, and DC bus names used in Table B 3.8.7-1. For example: 4.16 kVac ENGINEERED SAFETY FEATURE (ESF) buses, 480 Vac load centers, buses, motor control centers, and 120 Vac power distribution panels; 120 Vac vital buses; and 250/125 Vdc buses]. [Two] [divisions] (or subsystems) are required for safety function redundancy; [any one] [division] (or subsystem) provides safety function, but without worst-case single-failure protection.}

{VS-BWR/6: The onsite Class 1E AC and DC electrical power distribution system is divided by [division] into [three] independent AC and DC electrical power distribution subsystems. Each [divisional AC and DC electrical power distribution subsystem is comprised of [PLANT SPECIFIC: List the major AC, AC vital, and DC bus names used in Table B 3.8.7-1. For example: 4.16 kVac ESF buses, 480 Vac load centers, buses, motor control centers, and 120 Vac power distribution panels; 120 Vac vital buses; and 250/125 Vdc buses]. All three [divisions] (or subsystems) are required for safety function redundancy; any two [divisions] (or subsystems) provide safety function, but without worst-case single-failure protection.}

Each [4.16 kV ESF bus] has at least [one separate and independent offsite source of power] as well as a dedicated onsite diesel generator source. Each [4.16 kV ESF bus] is normally connected to a preferred source. During a loss of one offsite power source to the [4.16 kV ESF buses], a [4.16 kV] transfer scheme is accomplished by utilizing a time-delayed bus undervoltage relay. If all offsite sources are unavailable, the onsite emergency power system will 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

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

found in the Bases for Specification 3.8.1, "AC Sources—Operating," and the Bases for Specification 3.8.3, "DC Sources—Operating."

The secondary plant distribution is at [480] V. The [480] V distribution system includes [PLANT SPECIFIC: List items such as emergency buses, load [illegible] transformers; the identifying numbers of these [illegible] also be included]. The [480] V load centers f[illegible] subsystem are located [in separate rooms in the control building]. Control power for the [480] V breakers is supplied from the [Class 1E batteries], as described in the Bases for Specification 3.8.3, "DC Sources—Operating."

The Class 1E [480] Vac motor control centers and power distribution panels are powered from [PLANT SPECIFIC: Provide bus and/or load center information and nomenclature].

The Class 1E [120] V power distribution panels are powered from [PLANT SPECIFIC: Provide distribution panel information and nomenclature]. All [120] V distribution panels that provide control or instrumentation necessary for operation of safety systems are required to be included in this specification.

The [120] Vac vital buses [2YV1, 2YV2, 2YV3, and 2YV4] are arranged in four load groups and are normally powered from [PLANT SPECIFIC: Provide power path and nomenclature between the inverters and the buses]. 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, and its use is governed by LCO 3.3.5, "Inverters—Operating." Each constant voltage source transformer is powered from [PLANT SPECIFIC: Provide power path and nomenclature].

There are {VS-BW,CE,W,BWR/4: [two]} {VS-BWR/6: [three]} independent [125/250] Vdc electrical power distribution subsystems. [PLANT SPECIFIC: Provide power path and nomenclature for the DC power distribution system.]

The list of all required distribution buses is located in Table B 3.8.7-1.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in [FSAR Chapter 6, "Engineering Safety Features," and Chapter 15, "Accident Analyses,"] assume ESF systems are OPERABLE. The AC and DC 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 (RCS) and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 3.6 (Containment Systems).

The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one [division] of the onsite or offsite AC electrical power sources, DC electrical power sources, and associated distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power; and

b. A worst-case single failure.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The required AC and DC [divisional] power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC 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 {VS-BW,CE,W,BWR/4: [Division 1 and 2]} {VS-BWR/6: [Division 1, 2, and 3]} AC and DC electrical power distribution subsystems are required to be OPERABLE.

{VS-BW,CE,W,BWR/4: Maintaining the [Division 1 and 2] AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Either [division] of the AC and DC

(continued)

(continued)

BASES (continued)

LCO (continued)

power distribution system is 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 will not prevent safe shutdown of the reactor.}

{VS-BWR/6: Maintaining the [Division 1, 2, and 3] AC and DC 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 will not prevent safe shutdown of the reactor.}

OPERABILITY is met, as it applies to AC and DC electrical power distribution subsystems, provided the associated buses, transformers, load centers, motor control centers, and electrical circuits are fully energized to their proper voltages and frequencies. The components of each AC and DC electrical power distribution subsystem must be kept within the manufacturers' specifications for environmental factors such as temperature and humidity.

In addition, breakers must be open between redundant buses to prevent two power sources from being paralleled. The open breakers also preclude unlimited continued operation where a single failure (loss of one source) could cause a loss of two redundant buses. Thus, if two sources are paralleled through redundant distribution buses that are cross-tied, the distribution buses must be considered inoperable. If two redundant buses are powered from the same source, however, only the bus that is not being powered from its normal source shall be considered inoperable.

[For this facility, as a minimum, the following support systems associated with the AC and DC electrical power distribution subsystems governed by LCO 3.8.7 to ensure their OPERABILITY are as follows:]

[For this facility, the supported systems affected by the inoperability of the support systems governed by LCO 3.8.7, and the justification of whether or not each supported system is declared inoperable, are as follows:]

(continued)

BASES (continued)

APPLICABILITY

The AC and DC electrical power distribution subsystems are required to be OPERABLE in {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: 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.

AC and DC electrical power distribution subsystem requirements for {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} are covered in the Bases for Specification 3.8.8.

A Note has been added to provide clarification that for this LCO, all required AC and DC electrical power distribution subsystems shall be treated as an entity with a single Completion Time.

ACTIONS

A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels, except AC vital buses, in one division inoperable the remaining AC electrical power distribution {VS-BW,CE,W,BWR/4: subsystem is} {VS-BWR/6: 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 {VS-BW,CE,W,BWR/4: subsystem} {VS-BWR/6: 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 a determined amount of time ([ ] hours), not to exceed 8 hours if more than two systems are made inoperable because of the distribution system inoperability.

(continued)

(conti...)

BASES (continued)

ACTIONS (continued)

[ ] hours will be a specific number for each specific bus in each specific plant. For a specific bus, [ ] hours is defined as the most limiting Completion Time of all the supported systems that are made inoperable by the inoperability of the bus. Thus, a prior determination must be made to obtain the most limiting Completion Time of all the systems supported by each bus. [ ] does not exceed 8 hours, however, if three or more systems are made inoperable by the bus inoperability.

Note that the equipment referred to is all in one [division] power distribution subsystem.

When equipment governed by LCO 3.8.7 is inoperable in {VS-BW,CE,W,BWR/4: both [divisions]} {VS-BWR/6: two or more [divisions]} and results in loss of functional capability, then LCO 3.0.3 must be immediately entered.

B.1

With one AC vital bus inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since 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. For an AC vital bus to be considered OPERABLE, it must be powered from its DC-to-AC inverter. An alternate Class 1E constant voltage source may be used if approved for this purpose as stated in the licensing basis of the plant. Requirements imposed on the alternate source are governed by LCO 3.8.5, "Inverters—Operating." 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.

{VS-BWR/6: However, if the inoperable AC vital bus is associated with [Division 3], then continued operation for up to a [2-hour] Completion Time is plant specific and is meant to be the most limiting Completion Time for all systems that a [Division 3] AC vital bus supports;

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

furthermore, the [2-hour] Completion Time is not to exceed 8 hours if more than two systems are made inoperable because of the [Division 3] AC vital bus inoperability. The [2-hour] Completion Time for [Division 3] takes into account the importance to safety of restoring the [Division 3] 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.}

When more than one AC vital bus is inoperable, there is a loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

C.1

With one or more required DC buses in one [division] inoperable the remaining DC electrical power distribution {VS-BW,CE,W,BWR/4: subsystem is} {VS-BWR/6: 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 {VS-BW,CE,W,BWR/4: subsystem} {VS-BWR/6: 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. The 2-hour Completion Time for DC buses is consistent with Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. [1]).

{VS-BWR/6: However, if the inoperable DC bus is associated with [Division 3], then continued operation for up to a [2-hour] Completion Time is plant specific and is meant to be the most limiting Completion Time for all systems that a [Division 3] DC bus supports; furthermore, the [2-hour] Completion Time is not to exceed 8 hours if more than two systems are made inoperable because of the [Division 3] DC bus inoperability. The [2-hour] Completion Time for [Division 3] takes into account the importance to safety of restoring the [Division 3] DC bus to OPERABLE status, the redundant capability afforded by the other OPERABLE DC buses, and the low probability of a DBA occurring during this period.}

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

When one or more DC buses are inoperable in more than one AC and DC electrical power distribution subsystem, there is a loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

D.1

With one or more features specified under Condition A, B, or C inoperable in the one [division] of AC and DC electrical power distribution subsystem AND one or more required support or supported features, or both, inoperable associated with the other OPERABLE AC and DC electrical power distribution subsystem(s), or with opposite OPERABLE DC electrical power subsystem(s), or both, there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the LCOs of the support or supported feature, or both, takes into consideration the loss of function situation, LCO 3.0.3 may not need to be entered.

E.1

With one or more features specified under Condition A, B, or C inoperable in one [division] of AC and DC electrical power distribution subsystem, verify that the Required Actions for those supported systems declared inoperable by the support features governed by LCO 3.8.7 have been initiated and within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that need to be declared inoperable upon the failure of one or more features specified under Condition E.

Required Action E.1 ensures that those identified Required Actions associated with supported systems affected by the inoperability of the supported features governed by this LCO have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition E of this LCO.]

[For this facility, the identified supported systems Required Actions are as follows:]

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

F.1 and F.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable devices or components cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6 hours} {VS-GE: 12 hours} and in {VS-BW,CE,W: MODE 5} {VS-GE: MODE 4} within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with all the required circuit breakers closed and the buses energized from normal power. 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 AC and DC electrical power distribution subsystems, and other indications available in the control room that will alert the operator to subsystem malfunctions.

SR 3.8.7.2

This Surveillance verifies that the frequency on the AC vital buses is within limits. [For this facility, the purpose of this Surveillance is as follows:]

The 7-day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems and other indications available in the control room that will alert the operator to subsystem malfunctions.

REFERENCES

1. Regulatory Guide 1.93, "Availability of Electric Power Sources," U.S. Nuclear Regulatory Commission, December 1974.

{This version of Table B 3.8.7-1 is VS-BW,CE,W,BWR/4}

Table B 3.8.7-1 (page 1 of 1)

AC and DC Electrical Power Distribution System

TYPE	VOLTAGE	[Division 1]*	[Division 2]*
AC safety buses	[4160 V]	[ESF Bus] [NB01]	[ESF Bus] [NB02]
	[480 V]	Load Centers [NG01, NG03]	Load Centers [NG02, NG04]
	[480 V]	Motor Control Centers [NG01A, NG01I, NG01B, NG03C, NG03I, NG03D]	Motor Control Centers [NG02A, NG02I, NG02B, NG04C, NG04I, NG04D]
	[120 V]	Distribution Panels [NP01, NP03]	Distribution Panels [NP02, NP04]
DC buses	[125 V]	Bus [NK01] from battery [NK11] and charger [NK21]	Bus [NK02] from battery [NK12] and charger [NK22]
		Bus [NK03] from battery [NK13] and charger [NK23]	Bus [NK04] from battery [NK14] and charger [NK24]
		Distribution Panels [NK41, NK43, NK51]	Distribution Panels [NK42, NK44, NK52]
AC vital buses	[120 V]	Bus [NN01] from inverter [NN11] connected to bus [NK01]	Bus [NN02] from inverter [NN12] connected to bus [NK02]
		Bus [NN03] from inverter [NN13] connected to bus [NK03]	Bus [NN04] from inverter [NN14] connected to bus [NK04]

* Each [division] of the AC and DC electrical power distribution system is a subsystem.

(This version of Table B 3.8.7-1 is VS-BW,CE,W,BWR/6)

Table B 3.8.7-1 (page 1 of 1)

AC and DC Electrical Power Distribution System

TYPE	VOLTAGE	[Division 1]*	[Division 2]*	[Division 3]*
AC safety buses	[4160 V]	[ESF Bus] [NB01]	[ESF Bus] [NB02]	[ESF Bus] [NB03]
	[480 V]	Load Centers [NG01, NG03]	Load Centers [NG02, NG04]	
	[480 V]	Motor Control Centers [NG01A, NG01I, NG01B, NG03C, NG03I, NG03D]	Motor Control Centers [NG02A, NG02I, NG02B, NG04C, NG04I, NG04D]	Motor Control Centers [NG05A, NG05C]
	[120 V]	Distribution Panels [NP01, NP03]	Distribution Panels [NP02, NP04]	Distribution Panels [NP05, NP06]
DC buses	[125 V]	Bus [NK01] from battery [NN11] and charger [NK21]	Bus [NK02] from battery [NK12] and charger [NK22]	Bus [NK05] from battery [NK15] and charger [NK25]
		Bus [NK03] from battery [NN13] and charger [NK23]	Bus [NK04] from battery [NK14] and charger [NK24]	
		Distribution Panels [NK41, NK43, NK51]	Distribution Panels [NK42, NK44, NK52]	Distribution Panel [NK45]
AC vital buses	[120 V]	Bus [NN01] from inverter [NN11] connected to bus [NK01]	Bus [NN02] from inverter [NN12] connected to bus [NK02]	Bus [NN05] from inverter [NN15] connected to bus [NK05]
		Bus [NN03] from inverter [NN13] connected to bus [NK03]	Bus [NN04] from inverter [NN14] connected to bus [NK04]	

* Each [division] of the AC and DC power distribution system is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution System—Shutdown

BASES

BACKGROUND

A description of the AC and DC electrical power distribution system is provided in the Bases for Specification 3.8.7, "Distribution System—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other modes of operation, the GDC (Ref. 2), among other requirements, are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to ensure that the plant is operated within its design basis, with regard to distribution systems, the requirements established in the TS must be consistent with the GDC related to electrical systems, as well as with other GDC related to safety-related systems, since the AC and DC electrical power distribution subsystems comprise a typical support system.

In general, when the plant is shut down, the TS requirements ensure that the plant has the capability to mitigate the

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE; or

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W,: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when the Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops—MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation—Low Water Level."}} {VS-GE: the OPERABILITY of the two RHR shutdown cooling subsystems is always required in MODE 4, and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications [VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal—Shutdown," and 3.9.8, "Residual

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Heat Removal—Low Water Level."} Therefore, in these conditions, [portions of] [Division 1 and 2] AC and DC electrical power distribution subsystems are required to be OPERABLE as support systems.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

LCO 3.8.8.a requires OPERABILITY of one [division] AC and DC electrical power distribution subsystem. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from this safety [division] and that all required AC and DC sources, as well as the distribution subsystem itself, will be OPERABLE so that the AC and DC sources and distribution subsystem will be capable of fully supporting the required loads.

When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.8.b requires that they receive power from the [necessary portions of the] other [division] AC and DC electrical power distribution subsystem. Therefore, LCO 3.8.8.b requires [the necessary portions of] this other [division] DC electrical power subsystem to be OPERABLE.

{VS-BWR/6: LCO 3.8.8.c requires OPERABILITY of the [division 3] AC and DC electrical power distribution subsystem when the High Pressure Core Spray (HPCS) System is required to be OPERABLE, or when other loads assigned to the HPCS System [division] are required to be OPERABLE, or both.}

See the Bases for Specification 3.8.7 for additional information on AC and DC electrical power distribution subsystem OPERABILITY and AC and DC electrical power distribution support and supported systems.

LCO 3.8.8 specifies the minimum number of AC and DC electrical power distribution subsystems required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE: [or

(continued)

(continued)

BASES (continued)

LCO (continued)

moving loads over irradiated fuel in the primary or secondary containment]}. It 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, inadvertent reactor vessel draindown).

As described in the previous section, "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. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted provided the backup system is OPERABLE or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The AC and DC electrical power distribution subsystems comprise a typical support system.

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel 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 OPERABLE; and

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

AC and DC electrical power distribution subsystem requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.7, "Distribution System—Operating."

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required AC and DC electrical power distribution subsystems inoperable, some equipment is not receiving the minimum support it needs. Therefore, it is required to suspend CORE ALTERATIONS, handling of irradiated fuel, {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the 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 unit's safety systems.

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 unit's safety systems may be without power.

Required Action A.6 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one or more AC and DC electrical power distribution subsystems have been initiated and within the same Completion Time as that specified for Required Action A.5.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

Required Action A.6 ensures that those identified Required Actions associated with supported systems affected by the inoperability of one or more AC and DC electrical power distribution subsystems have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.]

[For this facility, the identified supported systems' Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution system is functioning properly, with all required circuit breakers closed and the buses energized from normal power. 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 AC and DC electrical power distribution subsystems, as well as other indications available in the control room that will alert the operator to subsystem malfunctions.

SR 3.8.8.2

This Surveillance verifies that the frequency on the AC vital buses is within limits. [For this facility, the purpose of this Surveillance is as follows:]

The 7-day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, as well as other indications available in the control room that will alert the operator to subsystem malfunctions.

REFERENCES

1. [Unit name] FSAR, Section [ ], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

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 plant 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 must 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 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

(continued)

(continued)

BASES (continued)

BACKGROUND (continued)

refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over 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).

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 [ ] ft [ ] inches from the outside of the reactor core. 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 does not reach beyond [ ] ft [ ] inches from the core.

The hoist switches open at a load lighter than the weight of a single fuel assembly in water. A fuel assembly in water weighs [715 (dry)] lb, and the switches are set at [680] lb.

"Refueling Equipment Interlocks" satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

To prevent criticality during refueling, the refueling interlocks ensure that fuel assemblies are not loaded with any control rod withdrawn or that a rod cannot be withdrawn while a fuel assembly is being loaded.

(continued)

(continued)

BASES (continued)

LCO (continued)

To prevent these conditions from developing, the all-rods-in, the refueling platform over-core position, the refueling platform main hoist fuel-loaded inputs, and the refueling equipment interlocks are required to be OPERABLE. These inputs and interlocks provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

[For this facility, OPERABLE refueling equipment interlocks and their associated inputs constitute the following:]

[For this facility, the following support systems are required OPERABLE to ensure refueling equipment interlock channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the refueling equipment interlocks channels inoperable and their justification are as follows:]

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 CORE ALTERATIONS with refueling equipment associated with the interlocks.

In MODES 1, 2, 3, and 4, the reactor pressure vessel (RPV) 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 plant must be placed in a condition in which the LCO does not apply. CORE ALTERATIONS with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn).

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

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates that 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 such that the entire channel is tested.

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 plant operations personnel.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. [Unit Name] FSAR, Section [ ], "[Title]."

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 plant procedures which 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 which has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4) and a rod selection signal (from the Reactor Manual Control System).

This specification assures that the performance of the refuel position one-rod-out interlock, in the event of a Design Basis Accident (DBA), 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 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.

The refuel position one-rod-out interlock and adequate SHUTDOWN MARGIN (LCO 3.1.1) prevent criticality by stopping withdrawal of more than one control rod. With one control

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

rod withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion.

"Refuel Position One-Rod-Out Interlock" satisfies Criterion 3 of the NRC Interim 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. Both channels of the refuel position one-rod-out interlock are required to be OPERABLE.

[For this facility, a refuel position one-rod-out interlock channel is considered OPERABLE when:]

[For this facility, the following support systems are required OPERABLE to ensure refuel position one-rod-out interlock channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the refuel position one-rod-out interlock channels inoperable and their justification are as follows:]

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 through 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 (RPS) (LCO 3.3.1.1) and the control rods (LCO 3.1.2) 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.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With one or both channels of the refuel position one-rod-out interlock inoperable, the refueling interlocks may not be 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 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

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 such that the entire channel is tested. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position).

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. The 1-hour Frequency to perform a CHANNEL FUNCTIONAL TEST when any control rod is withdrawn is similarly adequate.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."

(continued)

(continued)

BASES (continued)

REFERENCES (continued)

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. [Unit Name] FSAR, Section [ ], "[Title]."

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 (CRD) 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 SHUTDOWN MARGIN (LCO 3.1.1), the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1), the average power range monitor (APRM) 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 removal error during refueling in the FSAR (Ref. 2) assumes that the refueling interlocks and adequate SHUTDOWN MARGIN are in place. (continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Additionally, during refueling, all control rods must be fully inserted to ensure that an inadvertent criticality does not occur.

"Control Rod Position" satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

All control rods must be fully inserted during applicable refueling conditions to prevent an inadvertent criticality during refueling.

[For this facility, a control rod is considered to be fully inserted when:]

[For this facility, the following support systems are required OPERABLE to ensure that one or more control rods are fully inserted:]

[For this facility, those required support systems which upon their failure do not declare that one or more control rods are not fully inserted and their justification are as follows:]

[For this facility, the supported systems impacted because one or more control rods are not fully inserted and the justification of whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

During MODE 5, loading fuel into a core cell with the control rod withdrawn may result in inadvertent criticality. Therefore, the control rod 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.

An exception to this requirement is allowed (LCO 3.10.6) if fuel is being loaded in an approved spiral reload sequence that does not use a complete set of blade guides. The approved spiral reload sequence typically involves reloading

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

such that fuel is always being loaded on the periphery of the fueled zone. During the spiral reloading, all control rods in core cells containing fuel are fully inserted, and the control rod in the next cell to be loaded is fully inserted. This minimizes the reactivity insertion of each fuel assembly and the probability of a reactivity excursion.

This specification does not apply in MODES 1, 2, 3, and 4, since the vessel head is in place and refueling operations are not possible.

ACTIONS

A.1 and A.2

With a control rod 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 the completion of movement of a component to a safe condition.

Required Action A.2 initiates action to verify that the Required Actions have been initiated for the supported systems declared inoperable because of one or more control rods not fully inserted within the same Completion Time as that specified for Required Action A.1.

Required Action A.2 ensures that identified Required Actions associated with supported systems impacted because of one or more control rods not fully inserted, have been initiated. This can be accomplished by entering the supported systems LCOs or independently as a group of Required Actions needed to be initiated every time Condition A is entered. [For this facility, the identified supported systems Required Actions are as follows:]

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.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	The 12-hour Frequency considers the procedural controls over control rod movement during refueling as well as the redundant functions of the refueling interlocks.
REFERENCES	1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability." 2. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND	The two full-in position indication channels for each control rod provide 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 two full-in position indication channels 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 SHUTDOWN MARGIN (LCO 3.1.1), the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1), the average power range monitor (APRM) 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 removal error during refueling (Ref. 2) assumes that the refueling interlocks are OPERABLE and an adequate SHUTDOWN MARGIN is available. The two full-in position indication channels are 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 Interim Policy Statement.

(continued)

BASES (continued)

LCO

Each of the two control rod full-in position indication channels 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 interlock logic.

[For this facility, the following support systems are required OPERABLE to ensure control rod position indication channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the control rod position indication channels inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a control rod position indication channel and the justification of whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

During MODE 5, each control rod must have two 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 3.1.2, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor MODE switch in the refuel position, the full-in position indication channels are required to be OPERABLE to ensure that the refuel position one-rod-out interlocks are OPERABLE.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.3.1, and A.3.2

With one or more full-in position indication channels inoperable, alternative compensating actions must be taken to protect against potential reactivity excursions from new fuel insertions or control rod withdrawals.

The first (and safest) alternative involves immediately suspending CORE ALTERATIONS and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

Suspension of CORE ALTERATIONS and control rod withdrawal shall not preclude completion of the movement of a component to a safe condition.

The second alternative requires immediately initiating actions to fully insert the control rod(s) and disarm the drive(s) associated with the inoperable full-in position indicator(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.

An inoperable full-in channel may be bypassed to allow refueling operations to proceed. Under this condition, an alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication). If all fuel is removed from a core cell, the full-in position indications may be bypassed since the control rod may be withdrawn and the position indication is not required to be OPERABLE.

Required Action A.1 initiates action to verify that the Required Actions have been initiated for the supported systems declared inoperable because of the inoperability of one or more control rod position indication channels within the same Completion Time as that specified for other Required Actions in Condition A.

Required Action A.1 ensures that identified Required Actions associated with supported systems impacted because of the inoperability of one or more control rod position indication channels have been initiated. This can be accomplished by entering the supported systems LCOs, or independently as a group of Required Actions needed to be initiated every time Condition A is entered. [For this facility, the identified supported systems Required Actions are as follows:]

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels are verified to be OPERABLE when they are available for all fully inserted control rods.

The 24-hour Frequency is considered adequate because of the procedural controls on control rod withdrawals and the visual and audible indications available in the control room to alert the operator of control rods not fully inserted.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."

2. [Unit Name] FSAR, Section [ ], "[Title]."

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 (RPS), 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 SHUTDOWN MARGIN (LCO 3.1.1), the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1), the average power range monitor (APRM) 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 removal 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 backup protection should a prompt reactivity excursion occur. "Control Rod OPERABILITY—Refueling" satisfies Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if it is capable of being automatically inserted upon receipt of a scram signal, including scram accumulator pressure > [940] psig.

[For this facility, the following support systems are required OPERABLE to ensure control rod OPERABILITY during refueling:]

[For this facility, those required support systems which upon their failure do not declare the control rods inoperable and their justification are as follows:]

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 LCOs 3.1.2, 3.1.3, 3.1.4, and 3.1.5. During MODES 3 and 4, control rods are only allowed to be withdrawn under special operations LCO 3.10.3, "Single Control Rod Withdrawal—Hot Shutdown," and LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown," which provide 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 ensures that the shutdown and scram capabilities are not adversely affected.

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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 [940] psig.

SR 3.9.5.1 and SR 3.9.5.2

The 7-day Frequency considers equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights which indicate low accumulator charge pressures.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."

2. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND

The movement of fuel assemblies within containment with irradiated fuel in Containment, requires a minimum water level of [23] ft above the top of the RPV flange. During refueling, this maintains a sufficient water level in the containment, refueling cavity, refueling canal, fuel transfer canal, and spent-fuel 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 fuel assemblies, the water level in the refueling cavity and refueling canal 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 (Regulatory Position C.1.c of Ref. 1) allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet/cladding gap of all the dropped fuel-assembly rods is retained by the refueling cavity water. The fuel pellet/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 100 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 with allowable limits (Ref. 4).

"RPV Water Level" satisfies Criterion 2 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

A minimum water level of [23] ft 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.

[For this facility, the following support systems are required OPERABLE to ensure RPV water level indication channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the RPV water level indication channel inoperable and their justification are as follows:]

APPLICABILITY

Within the containment, LCO 3.9.6, "Reactor Pressure Vessel Water Level," is applicable when irradiated fuel assemblies are seated within the RPV and when fuel assemblies are being moved over or 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 over or 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 3.7.6.

ACTIONS

A.1

If the water level is < [23] ft above the top of the RPV flange, all operations involving movement of fuel assemblies shall be suspended immediately to ensure that a fuel-handling accident cannot occur. The suspension of fuel movement shall not preclude completion of movement to a safe position.

In the event that the required RPV water level indication channels are found inoperable, the RPV water level is considered to be not within limits and Required Action A.1 applies.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of [23] ft 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 above the top of the RPV flange 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, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel-Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors," U.S. Nuclear Regulatory Commission, March 23, 1972.

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. NUREG-0800, "Standard Review Plan," Section 15.7.4, "Radiological Consequences of Fuel-Handling Accidents," U.S. Nuclear Regulatory Commission.

4. Title 10, Code of Federal Regulations, Part 20, Section 20.101(2), "Radiation Dose Standards for Individuals in Restricted Areas."

B 3.9 REFUELING OPERATIONS

B 3.9.7 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. The RHR heat exchangers transfer heat to the Standby Service Water System (LCO 3.7.2). 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

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to inadequate cooling of the reactor fuel because of the resulting loss of coolant in the RPV. The loss of reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission-product barrier. One train of the RHR System is required to be OPERABLE and in operation to prevent this challenge.

Although the RHR system does not meet a specific criteria of the NRC Interim Policy Statement, it was identified in the Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a technical specification.

LCO

Only one RHR subsystem is required to be OPERABLE and in operation in MODE 5 with the water level ≥ [23] ft above the

(continued)

(continued)

BASES (continued)

LCO (continued)

RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay-heat-removal capability.

An OPERABLE RHR subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

[For this facility an RHR subsystem in operation constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure RHR System OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the RHR System inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of an RHR System and the justification of whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

One RHR subsystem must be OPERABLE and in operation in MODE 5, with the water level ≥ [23] ft 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"; Section 3.5, "Emergency Core Cooling System" and "Reactor Core Isolation Cooling"; and Section 3.6, "Containment Systems." RHR System requirements in MODE 5, when the water level is < [23] ft above the RPV flange, are given in LCO 3.9.8.

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

If no RHR subsystem is OPERABLE or is not in operation, actions shall be taken immediately to suspend operations involving an increase in reactor decay-heat load. Also, actions shall be taken to restore one RHR subsystem to OPERABLE status and operation within 15 minutes. The 15 minute Completion Time is sufficient for an operator to

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

initiate corrective action. In this Condition, the volume of water above the RPV flange provides adequate capability to remove decay heat from the reactor core. Actions must continue until at least one RHR subsystem is restored to OPERABLE status and to operation.

If at least one RHR subsystem is not restored to OPERABLE status within 15 minutes, additional actions are required to minimize any potential fission-product release to the environment. This includes initiating immediate action to restore the following to OPERABLE status: secondary containment, one Standby Gas Treatment System subsystem, and one secondary containment isolation valve and associated instrumentation in each associated penetration not isolated. 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 does not mean 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.

Required Action A.6 initiates action to verify that the Required Actions have been initiated for the supported systems declared inoperable because of the inoperability of required RHR subsystems within the same Completion Time as that specified for other Required Actions in Condition A.

Required Action A.6 ensures that identified Required Actions associated with supported systems impacted because of the inoperability of required RHR subsystems have been initiated. This can be accomplished by entering the supported systems LCOs, or independently as a group of Required Actions needed to be initiated every time Condition A is entered. [For this facility, the identified supported systems Required Actions are as follows:]

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	<u>SR 3.9.7.1</u> This surveillance verifies that the RHR subsystem is OPERABLE, in operation, and circulating reactor coolant. The 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 3.9.8 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 the associated recirculation loop. The RHR heat exchangers transfer heat to the Standby Service Water System (LCO 3.7.2). The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to inadequate cooling of the reactor fuel due to the resulting loss of coolant in the reactor pressure vessel (RPV). The loss of reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission-product barrier. Two trains of the RHR System are required to be OPERABLE, and one in operation, to prevent this challenge.

Although the RHR System does not meet a specific criterion of the NRC Interim Policy Statement, it was identified in the Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a technical specification.

LCO

In MODE 5, with the water level < 23 ft above the RPV flange, both RHR subsystems must be OPERABLE. Additionally, one subsystem of RHR must be in operation.

(continued)

(continued)

BASES (continued)

LCO (continued)

An OPERABLE RHR subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

[For this facility, an RHR subsystem in operation constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure RHR System OPERABILITY:]

[For this facility, these required support systems which upon their failure do not declare the RHR System inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of an RHR System and the justification of whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

Two RHR subsystems are required to be OPERABLE, and one must be in operation in MODE 5, when the water level is < [23] feet above the top of the RPV flange to provide decay-heat removal. RHR System requirements in other MODES are covered by LCO in Section 3.4, "Reactor Coolant System"; Section 3.5, "Emergency Core Cooling System" and "Reactor Core Isolation Cooling"; and Section 3.6, "Containment Systems." RHR System requirements in MODE 5 when the water level is ≥ [23] ft above the RPV flange are given in LCO 3.9.7.

ACTIONS

A.1 and A.2

If one RHR subsystem is inoperable or not in operation, actions shall be taken and continued until the RHR subsystem is restored to OPERABLE status and operation or a water level ≥ [23] ft is established above the RPV flange. Raising the water level will result in conditions that require only a single RHR subsystem to be OPERABLE and in operation (LCO 3.9.7). A Completion Time of 15 minutes is allowed for an operator to initiate corrective action.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1, B.2, B.3, B.4, and B.5

If no RHR subsystem is OPERABLE or is not in operation, actions shall be initiated immediately and continued without interruption to restore one RHR subsystem to OPERABLE status and operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR subsystems and one operating RHR subsystem should be accomplished expeditiously.

With no RHR subsystem OPERABLE or in operation, alternate actions shall have been initiated within 15 minutes under Condition A to establish ≥ [23] ft of water above the top of the RPV flange. Furthermore, when the LCO cannot be fulfilled, alternate decay-heat-removal methods, as specified in the plant's Abnormal and Emergency Operating Procedures, should be implemented. These include the use of the Reactor Water Cleanup (RWCU) System, operating with the regenerative heat exchanger bypassed. The method used to remove decay heat should be the most prudent and the safest choice, based upon plant conditions.

If at least one RHR subsystem is not restored to OPERABLE status immediately, additional actions are required to minimize any potential fission-product release to the environment. This includes initiating immediate action to restore the following to OPERABLE status: secondary containment, one Standby Gas Treatment System subsystem, and one secondary containment isolation valve and associated instrumentation in each associated penetration not isolated. 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 does not mean to perform the surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

Required Action B.5 initiates action to verify that the Required Actions have been initiated for the supported

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

systems declared inoperable because of the inoperability of required RHR subsystems within the same Completion Time as that specified for other Required Actions in Condition B.

Required Action B.5 ensures that identified Required Action associated with supported systems impacted because of the inoperability of required RHR subsystems have been initiated. This can be accomplished by entering the supported systems LCOs, or independently as a group of Required Actions needed to be initiated every time Condition B is entered. [For this facility, the identified supported systems Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

This surveillance verifies that one RHR subsystem is OPERABLE, in operation, and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay-heat-removal capability. In addition, this surveillance verifies that the other RHR subsystem is OPERABLE. 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 (ISLH) Testing Operation

BASES

BACKGROUND

The purpose of this MODE 4 special operations LCO is to give flexibility and to obtain a good inspection in performing certain reactor coolant pressure tests 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 3.4.9. 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 (at a given pressure) increases. 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 per LCO 3.4.9 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

The acceptance criterion for permitting irradiated fuel to be in the reactor while allowing hydrostatic testing to be performed is that the offsite dose criteria of [10 CFR—Title] be met. The leak-break frequency of the reactor pressure vessel boundary during the performance of a hydrostatic test has been categorized as a [ ] faulted condition (Ref. 2). The evaluation of the potential fission-product release and dose to the offsite public due to potential fuel melt as a result of dryout from a leak or break event during a hydrostatic test has been approved by the NRC (Ref. 3).

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing when the reactor coolant temperature is > 200°F effectively provides an exception to MODE 3 requirements including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems. Since the hydrostatic or leak tests are performed water solid, at 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 3.4.7, "Reactor Coolant Specific Activity," is 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, (Ref. 3). The consequences of a steam leak under pressure testing conditions with secondary containment OPERABLE will be conservatively bounded by the consequences of the accident [postulated main steam line break (MSLB) outside of primary containment] analysis described in Reference 4. The Reference 3 analysis of the postulated MSLB outside of primary containment is bounding because [explain]. Therefore, requiring the secondary containment to be OPERABLE will conservatively ensure that any potential airborne radiation from steam leaks will be filtered through the Standby Gas Treatment System (SGTS), thereby limiting 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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

subsystems as required in MODE 4 by LCO 3.5.2 would be more than adequate to keep the core flooded under this low decay heat load condition (Ref. 3). 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.

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. Operation at reactor coolant temperatures > 200°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°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. [For this facility, the MODE 4 applicable LCOs are as follows:] This special operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "N/A." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 200°F for the purposes of performing either an inservice leak or hydrostatic test.

In order for this special operations LCO to accomplish its objective, the SRs for LCO 3.6.4.1, LCO 3.6.4.2, LCO 3.6.4.3, and LCO 3.7.2 must be met and the following additional support systems must be OPERABLE: [List].

(continued)

(continued)

BASES (continued)

LCO (continued)

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 the ISLH tests so that these operations can be considered as in MODE 4 even though the reactor coolant temperature is > 200°F. The additional requirement for secondary containment OPERABILITY per the imposed MODE 3 requirements provides conservatism in the response of the facility to any event that may occur. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements shall be entered and complied with immediately. Required Action A.1 has been modified by a Note which clarifies the intent of another LCO's [list] Required Action to be in MODE 4 including reducing the average reactor coolant temperature to ≤ 200°F.

A.2.1 and A.2.2

Required Action A.2.1 and Required Action A.2.2 are alternate ACTIONS that can be taken instead of Required Action A.1 and are provided 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 24-hour Completion Time 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 of [°F] to ≤ 200°F with normal cooldown procedures.

(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.
REFERENCES	1. ASME Boiler and Pressure Vessel Code. Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." 2. [Unit Name] FSAR, Section [ ], "[Title]." 3. [Unit Name] FSAR, Section [ ], "[Title]." 4. [Unit Name] FSAR, Section [ ], "[Title]."

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 periodic testing in MODES 3, 4, and 5 of various interlocks and calibrations by imposing administrative controls on plant operations.

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 OR HOTSTANDBY—Selects NMS scram function for low neutron flux level operation (intermediate 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.

Operation of the reactor mode switch from one position to another may be required to confirm certain aspects of these various interlocks during periodic tests and calibrations.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is to preclude fuel failure by precluding reactivity excursions or core criticality.

The rod scram and 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 which could potentially result in fuel failure. Interlock testing which requires moving the reactor mode switch to other positions (RUN or HOT standby or startup) while in Modes 3, 4, or 5, requires administratively maintaining all control rods inserted and no other CORE ALTERATIONS in progress. With all control rods inserted 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 unintentional rod withdrawal or rod drop, the accident analysis demonstrates that fuel failure will not occur (Ref. 2). [Discuss main accident events analyzed.]

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 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 3.10.3, LCO 3.10.4, and LCO 3.10.7) without meeting this LCO or its ACTIONS. If any testing is performed which involves the reactor mode switch interlocks and requires its repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, it 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 per 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.

(continued)

(continued)

BASES (continued)

LCO (continued)

Since rod withdrawal could inadvertently occur while in MODES 3 or 4 with the reactor mode switch in the hot standby or startup, or run position, the rod block is [explain why rod block is not in effect]. 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). The refueling equipment interlocks (LCO 3.9.1) 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 operations. The additional controls of administratively not permitting other core alterations will adequately ensure that the reactor does not become critical during these tests.

To ensure the control rods are fully inserted and no other CORE ALTERATIONS are in progress, the SRs of this LCO must be met and the following additional support systems must be OPERABLE [List].

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 plant 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 while in other modes. Such interlock testing may consist of required surveillances or calibrations, 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 criticality during CORE ALTERATIONS) can be administratively controlled adequately during the performance of certain tests.

(continued)

BASES (continued)

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this special operations LCO. Compliance will also result in exiting the Applicability of this special operations LCO.

All CORE ALTERATIONS, 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. This will preclude potential mechanisms which 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 to 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 must 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 Action is not applicable in MODES 3 and 4 since only the shutdown position is allowed in these MODES. The 1-hour Completion Time for Required Actions A.2, A.3.1, and A.3.2 provides sufficient time to normally insert the control rods based on operating experience and is acceptable given that all operations which could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this special operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in shutdown (or refuel for MODE 5). The functions of the reactor mode switch interlocks which are not in effect due to the testing in progress are adequately compensated for by the special operations LCO requirements. The administrative controls to ensure that the operational requirements continue to be met are to be periodically verified. The surveillances performed at the [12-hour] and [24-hour] Frequency are intended to provide appropriate assurance that each operating shift is aware of and verify compliance with these special operations LCO requirements.

(continued)

BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [7], "[Title]."
2. [Unit Name] FSAR, Section [ ], "[Title]."

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, 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 will arise while in MODE 3 which 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 SHUTDOWN MARGIN (SDM) will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures which 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)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Alternate backup protection can be obtained by assuring that a five-by-five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal.

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODES 3 and 4 operation 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 and LCO 3.10.4) 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. The refueling interlocks of LCO 3.9.2, 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, 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.

In order for the control rods to be considered fully inserted and the control rods in the five-by-five array to be disarmed, the SRs of this LCO must be met and the following support systems must be OPERABLE [list].

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs [List.] In MODES 3 and 4, control rod withdrawal is only allowed if performed in

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

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), and scram functions (LCO 3.3.1.1 and LCO 3.9.5) or the added administrative control in Item D.2 of this special operations LCO minimizes potential reactivity excursions.

ACTIONS

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 which clarifies the intent of any other LCO's Required Actions, in accordance with the other applicable LCOs, to insert all control rods and to also require exiting this special operations Applicability LCO by returning the reactor mode switch to the shutdown position.

A.2.1 and A.2.2

Required Action A.2.1 and Required Action A.2.2 are alternative ACTIONS that can be taken instead of Required Action A.1 and are provided to restore compliance with the normal MODE 3 requirements, thereby exiting this special operations LCO's Applicability. All insertable control rods are required to be 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 1-hour Completion Time for both of these Required Actions 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	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 preclude the possibility of criticality. Also, SR 3.10.3.3 verifies that all other control rods are fully inserted. The 24-hour Frequency is acceptable because of the administrative controls on control rod withdrawals and the protection afforded by the LCOs involved and hardware interlocks which preclude additional control rod withdrawals.
REFERENCES	1. [Unit Name] FSAR, Section [15], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single Control Rod Withdrawal—Cold Shutdown

BASES

BACKGROUND	The purpose of this MODE 4 special operation LCO is to permit the withdrawal of a single control rod for testing, 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 will 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 SHUTDOWN MARGIN (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. Alternate backup protection can be obtained by assuring that (continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

a five-by-five array of control rods, centered 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.

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 3 and MODE 4 operations 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 and LCO 3.10.3) without meeting this special operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, cont: .s consistent with those required during refueling must be implemented and this special operations LCO applied.

The refueling interlocks of LCO 3.9.2 required by this special operations LCO 3.10.4 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 and, therefore, LCO 3.9.2 to fail to be met. At this time, a control rod withdrawal block will 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 this special operations LCO's requirements in item D.1. Alternatively, when the scram 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. This precludes the possibility of criticality upon withdrawal of this control rod, including its CRD.

(continued)

(continued)

BASES (continued)

LCO (continued)	Additionally, in order for this special operations LCO to be met, the associated SRs must be met and the following support systems must be OPERABLE [list].
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 one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1 and LCO 3.9.5), or the added administrative controls in Item C.2 of this special operations LCO provide mitigation of potential reactivity excursions.
ACTIONS	<u>A.1, A.2.1, and A.2.2</u> If one or more of the LCOs or 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 exemptions allowed in this special operations LCO. Required Action A.1 has been modified by a Note which clarifies the intent of any other LCO's Required Actions, in accordance with the other applicable LCOs, to insert all control rods and to also require exiting this special operations Applicability LCO by returning the reactor mode switch to the shutdown position. 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, the ACTIONS require that the control rod be inserted and the reactor mode switch placed in the shutdown position. The 1-hour Completion Time for Required Actions A.2.1 and A.2.2 provides sufficient time to normally insert the control rods.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1, B.2.1, and B.2.2

If one or more of the LCOs or 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 control rod drive must immediately be suspended. If the CRD has been removed such that the control rod is not insertable, these ACTIONS require the most expeditious action be taken to either restore the CRD and insert its control rod or restore compliance with this special operations LCO.

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 (LCO 3.9.2, "refuel position one-rod-out interlock"; LCO 3.9.4, "Control Rod Position Indication"; LCO 3.3.1.1, "Reactor Protection System Instrumentation"; Functions 1.a, 1.b, 2.a, 2.e, 11, and 12 of Table 3.3.1.1-1 for MODE 5, LCO 3.3.8.2, "MODE 5, Reactor Protection System Electric Power Monitoring," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling") 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. Also, all the control rods are verified to be inserted as well as the control rod withdrawal block. 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 provides assurance that those control rods whose position indication instrumentation is inoperable, are fully inserted. 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.

REFERENCES

1. [Unit Name] FSAR, Section [15], "[Title]."

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 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 to normal refueling procedures as do the refueling interlocks described above, which 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 that 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 functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (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 assuring 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).

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 5 operation with any of

(continued)

(continued)

BASES (continued)

LCO (continued)

the following—LCO 3.3.1.1, LCO 3.3.1.3, LCO 3.3.8.2, 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 3.3.1.3, 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). Assuring 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, "Reactor Protection System Instrumentation," and LCO 3.9.2 would have otherwise provided.

The exemption granted in this special operations LCO to assume that the withdrawn control rod is the highest worth control rod to satisfy LCO 3.1.1, "Shutdown Margin (SDM)," and the inability to withdraw another control rod during this operation without additional SDM demonstrations, is conservative (i.e., the withdrawn control rod may not be the highest worth control rod).

[For this facility, an OPERABLE control rod block constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure control rod block OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not required declaring the control rod block inoperable and their justification are as follows:]

(continued)

BASES (continued)

APPLICABILITY

MODE 5 operations are controlled by existing LCOs [list]. The allowance to comply with this special operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.1.3, 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.

ACTIONS

A.1, A.2.1, and A.2.2

If 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 3.3.1.3, 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 ACTIONS be implemented in a very short time and carried through in an expeditious manner to either restore the CRD and insert its control rod or restore compliance with this special operations LCO.

In the event that the control rod block is found inoperable, Required Action A.1, Required Action A.2.1, and Required Action A.2.2 apply.

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 other control rods are fully inserted is required to assure the SDM is within limits. Verification that the local five-by-five array of control rods 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 provides assurance that those control rods whose position indication instrumentation is inoperable are fully inserted. The Surveillance for LCO 3.1.1, which is made applicable by this special operations LCO, is required in

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

order to establish that this special operations LCO is being met. Verification that no other CORE ALTERATIONS are being made is required to assure 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 controls on control rod removal and hardware interlocks to block an additional control rod withdrawal.

REFERENCES

1. [Unit Name] FSAR, Section [15], "[Title]."

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 SHUTDOWN MARGIN 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

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

bypassed for each withdrawn control rod if all fuel has been removed from 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.

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 5 operation with LCO 3.9.3, 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. 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 control rod was previously removed under the provisions of another LCO must be removed.

When loading fuel into the core with multiple control rods withdrawn, special [spiral] reload sequences are used to ensure that reactivity additions are minimized. Otherwise, all control rods must be fully loaded before loading fuel.

Additionally, in order for this LCO to be met, the associated SRs must be met and the following support systems must be OPERABLE [List].

APPLICABILITY

MODE 5 operations are controlled by existing LCOs. The exemption from other LCO requirements (e.g., the ACTIONS of LCO 3.9.4) allowed by this special operations LCO is appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, and A.2.2

If the requirements of this special operations LCO are not met, the immediate implementation of these Required Actions restore 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 exemptions 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 ACTIONS be implemented in a very short time and carried through in an expeditious manner to either restore the affected CRDs and insert their control rods or 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. [Unit Name] FSAR, Section [15], "[Title]."

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) such that only the specified control rod sequences and relative positions required by LCO 3.1.6 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 SHUTDOWN MARGIN 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 exemptions 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, 2, 3, and 4. 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 and, therefore, special CRDA analyses were performed to demonstrate that these special sequences will not result in unacceptable consequences should a CRDA occur during the testing. The safety analysis for the special CRDA analysis that demonstrates acceptable consequences is in Reference 5. These special CRDA analyses are as follows

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS (continued)	[explain]. These analyses address the specific test being performed. The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.
LCO	As described in LCO 3.0.8, 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 exemptions 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 3.3.2.1.5 when it is necessary to deviate from the prescribed sequence (e.g., an inoperable control rod that must be fully inserted). Additionally, in order that this LCO be met, the associated SRs must be met, and the following support systems must be OPERABLE [list].
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, LCO 3.2.2, LCO 3.2.3, and LCO 3.3.2.1. With THERMAL POWER less than or equal to the LPSP of the RPC, the (continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

provisions of this special operations LCO are necessary to perform special tests which are not in conformance with the prescribed control rod sequences of 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 or special operations LCO 3.10.4 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) and scram functions (LCO 3.3.1.1 and LCO 3.9.5) or added administrative controls prescribed in the applicable special operations LCOs minimize potential reactivity excursions.

ACTIONS

A.1

With the requirements of this special operations 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 exempted 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 [list]. 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 3.3.2.1.5, 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-9-US, "General Electric Standard Application for Reactor Fuel," Supplement for United States, Section S.2.2.3.1, September 1988.
2. [Unit Name] FSAR, Section [ ], "[Title]."
3. ANF-87-66, Revision 1, "[Unit Name] Plant Transient Analysis."
4. ANF-87-67, Revision 1, "[Unit Name] Reload Analysis."
5. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.8 Shutdown Margin (SDM) Test—MODE 5

BASES

BACKGROUND

The purpose of this MODE 5 special operations LCO is to permit SHUTDOWN MARGIN (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 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 or 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.

[Provide a discussion of how the SDM test is done including the use of in sequence criticals and in some cases, not following the approved banked position withdrawal sequence (BPWS) (See LCO 3.10.7, "Control Rod Testing—Operating," which allows exception to the BPWS). LCO 3.10.7 also requires that the special sequences (outside the BPWS) must be programmed into the rod worth minimizer or be verified by a second licensed operator.]

APPLICABLE SAFETY ANALYSES

The acceptance criterion for performing the SDM test in MODE 5 is that the reactor remains subcritical.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Subcriticality is maintained by requiring the control rod block instrumentation to be OPERABLE, the rod pattern controller (RPC) control sequence to be programmed with the SDM test sequence or be verified by a second licensed operator, and all out-of-sequence withdrawals to be in the notch out mode, and [explain].

Prevention and mitigation of unacceptable reactivity excursions due to potential accidents during control rod withdrawals with the reactor mode switch in the startup or hot standby position while in MODE 5 is provided by the Intermediate Range Monitor (IRM) neutron flux scram (LCO 3.3.1.1), average power range monitor (APRM) neutron flux scram (LCO 3.3.1.1), and control rod block instrumentation (LCO 3.3.2.1). The limiting reactivity excursion during startup conditions while in MODE 5 is the control rod drop accident (CRDA).

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1, 2, 3, and 4 are applicable. For sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1, 2, 3, and 4 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analysis may not be met and, therefore, special CRDA analyses are required to demonstrate that the SDM test sequence will not result in unacceptable cons uences should a CRDA occur during the testing. The safety a 'ysis for the special CRDA analyses that demonstrate acce able consequences is in Reference 5. These special A analyses are as follows [explain]. For the purpose of t test, 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, 2, and 3). In addition to the added requirements for the RPC, IRM, and APRM, the notch out mode is specified for out-of-sequence withdrawals. Requiring the notch out mode limits withdrawal steps to [explain] which limits inser ed reactivity to [explain].

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, 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. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the approved control rod withdrawal sequence must be enforced by the RPC (LCO 3.3.2.1, function 16, 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 [BPWS] specified in LCO 3.1.6 (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. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. This special operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup or hot standby position such that the SDM tests may be performed while in MODE 5. In addition to the requirements of this LCO, the normally required MODE 5 applicable LCOs [list] must be met.

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.

(continued)

BASES (continued)

ACTIONS

A.1

With the requirements of this LCO not met, 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.

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1 and SR 3.10.8.2

As indicated by the Notes, the control rod withdrawal sequences during the SDM tests may be enforced by the RPC (LCO 3.3.2.1, function 1b, 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 or the proper movement of control rods must be verified. This latter verification (i.e., SR 3.10.8.2) 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 3.10.8.3

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.

REFERENCES

1. NEDE-24011-P-A-9-US, "General Electric Standard Application for Reactor Fuel," Supplement for United States, Section S.2.2.3.1, September 1988.

2. [Unit Name] FSAR, Section [ ], "[Title]."

(continued)

(continued)

BASES (continued)

REFERENCES (continued)

3. ANF-87-66, Revision 1, "[Unit Name] Plant Transient Analysis."

4. ANF-87-67, Revision 1, "[Unit Name] Reload Analysis."

5. [Unit Name] FSAR, Section [ ], "[Title]."

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 fewer 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 acceptance criterion for allowing testing with the recirculation loops not operating in MODES 1 and 2 is that postulated accidents will not exceed their allowable consequences [explain].

The operation of the reactor coolant Recirculation System is an initial condition assumed in the analysis of 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 at or below [5%] of RATED THERMAL POWER (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 (Ref. 4). 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.

Additionally, other postulated accidents which are affected by the operation of the recirculation loops have been

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

determined to be acceptable during these tests or the Startup Test Program as analyzed in Reference 5 [explain the other analysis].

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. However, to perform testing at natural circulation conditions or with a single operating loop, operation must be limited to those tests defined in the Startup Test Program or approved PHYSICS TESTS performed at < [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.

[For this facility, an OPERABLE THERMAL POWER instrumentation constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure THERMAL POWER instrumentation OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the THERMAL POWER instrumentation inoperable and their justification are as follows:]

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

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

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 testing performed at natural circulation conditions or while operating with a single 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 1-hour Completion Time 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% of RTP, or unapproved testing at natural circulation), the reactor mode switch should immediately be 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 is to prevent unacceptable consequences from an accident initiated from outside the analysis bounds. Also, operation beyond authorized bounds should be terminated upon discovery.

In the event that the required THERMAL POWER instrumentation is found inoperable Required Action B.1 applies.

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.

(continued)

BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [14], "[Title]."
2. Title 10, Code of Federal Regulations, Part 50.59, "Changes, Tests and Experiments."
3. [Unit Name] FSAR, Section [6], "[Title]."
4. [Unit Name] FSAR, Section [ ], "[Title]."
5. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.10 Training Startups

BASES

BACKGROUND

The purpose of this special operations LCO is to permit training 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% of RATED THERMAL POWER (RTP) (equivalent to all OPERABLE intermediate range monitor (IRM) channels $\leq$ 25 or 40 divisions of full scale on range 7) and reactor coolant temperature < 200°F, the stored energy in the reactor core and coolant system is very low and a reduced complement of ECCS systems can provide the required core cooling, thereby allowing operation with one RHR subsystem in the shutdown cooling mode (Ref. 1).

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

As described in LCO 3.0.5, 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 $\leq$ 200°F. Under these conditions, the THERMAL POWER must be maintained below 1% of RTP (equivalent to all OPERABLE IRM channels $\leq$ 25 or 40 divisions of full scale on range 7) and the reactor coolant temperature must be $\leq$ 200°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.

[For this facility, an OPERABLE IRM channel and reactor coolant temperature instrumentation constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure IRM channel and reactor coolant temperature instrumentation OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the IRM channels and reactor coolant temperature instrumentation inoperable and their justification are as follows:]

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 which could require operation of both RHR subsystems in the LPCI mode of operation. Operations in all other MODES are unaffected by this LCO.

(continued)

BASES (continued)

ACTIONS

A.1

With the requirements of this LCO not met (i.e., any OPERABLE IRM channel > 25 or 40 division of full scale on range 7, or reactor coolant temperature ≥ 200°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 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.

In the event that the required IRM channels or reactor coolant temperature instrumentation are found inoperable, Required Action A.1 applies.

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. [Unit Name] FSAR, Section [ ], "[Title]."

APPENDIX A

Acronyms

The following acronyms are used, but not defined, in the Standard Technical Specifications:

AC	alternating current
CFR	Code of Federal Regulations
DC	direct current
FSAR	Final Safety Analysis Report
LCO	Limiting Condition for Operation
SR	Surveillance Requirement
GDC	General Design Criteria or General Design Criterion

The following acronyms are used, with definitions, in the Standard Technical Specifications:

ACOT	ANALOG CHANNEL OPERATIONAL TEST
ADS	Automatic Depressurization System
ADV	atmospheric dump valve
AFD	axial flux difference
AFW	auxiliary feedwater
AIRP	air intake, recirculation, and purification
ALARA	as low as reasonably achievable
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrence
AOT	allowed outage time
APD	axial power distribution
APLHGR	AVERAGE PLANAR LINEAR HEAT GENERATION RATE
APRM	average power range monitor
APSR	axial power shaping rod
ARO	all rods out
ARC	auxiliary relay cabinets
ARS	Air Return System
ARTS	Anticipatory Reactor Trip System
ASGT	asymmetric steam generator transient
ASGTPTF	asymmetric steam generator transient protective trip function
ASI	axial shape index
ASME	American Society of Mechanical Engineers

(continued)

ASTM	American Society for Testing Materials
ATWS	anticipated transient without scram
ATWS-RPT	anticipated transient without scram recirculation pump trip
AVV	atmospheric vent valve
BAST	boric acid storage tank
BAT	boric acid tank
BDPS	Boron Dilution Protection System
BIST	boron injection surge tank
BIT	boron injection tank
BOC	beginning of cycle
BOP	balance of plant
BPWS	banked position withdrawal sequence
BWST	borated water storage tank
BTP	Branch Technical Position
CAD	containment atmosphere dilution
CAOC	constant axial offset control
CAS	Chemical Addition System
CCAS	containment cooling actuation signal
CCGC	containment combustible gas control
CCW	component cooling water
CEA	control element assembly
CEAC	control element assembly calculator
CEDM	control element drive mechanism
CFT	core flood tank
CIAS	containment isolation actuation signal
COLR	CORE OPERATING LIMITS REPORT
COLSS	Core Operating Limits Supervisory System
CPC	core protection calculator
CPR	critical power ratio
CRA	control rod assembly
CRD	control rod drive
CRDA	control rod drop accident
CRDM	control rod drive mechanism
CREHVAC	Control Room Emergency Air Temperature Control System
CREFS	Control Room Emergency Filtration System
CREVS	Control Room Emergency Ventilation System
CRFAS	Control Room Fresh Air System
CS	core spray
CSAS	containment spray actuation signal

(continued)

APPENDIX A (continued)

CST	condensate storage tank
CVCS	Chemical and Volume Control System
DBA	Design Basis Accident
DBE	Design Basis Event
DF	decontamination factor
DG	diesel generator
DIV	drywell isolation valve
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DOP	dioctyl phthalate
DPIV	drywell purge isolation valve
DRPI	digital rod position indicator
EAB	exclusion area boundary
ECCS	Emergency Core Cooling System
ECW	essential chilled water
ECP	estimated critical position
EDG	emergency diesel generator
EFAS	Emergency Feedwater Actuation Syst=m
EFIC	emergency feedwater initiation and control
EFCV	excess flow check valve
EFPDs	effective full power days
EFPYs	effective full power years
EFW	emergency feedwater
EHC	electro-hydraulic control
EOC	end of cycle
EOC-RPT	end of cycle recirculation pump trip
ESF	engineered safety feature
ESFAS	Engineered Safety Feature Actuation System
ESW	essential service water
EVS	Emergency Ventilation System
FBACS	Fuel Building ⁄ir Cleanup System
FCV	flow control valve
FHAVS	Fuel Handling Area Ventilation System
FSPVS	Fuel Storage Pool Ventilation System
FRC	fractional relief capacity
FR	Federal Register
FTC	fuel temperature coefficient
FWLB	feedwater line break

(continued)

HCS	Hydrogen Control System; Hydrazine Control System
HCU	hydraulic control unit
HIS	Hydrogen Ignition System
HELB	high energy line break
HEPA	high efficiency particulate air
HMS	Hydrogen Mixing System
HPCI	high pressure coolant injection
HPCS	high pressure core spray
HPI	high pressure injection
HPSI	high pressure safety injection
HPSP	high power setpoint
HVAC	heating, ventilation, and air conditioning
HZP	hot zero power

ICS	Iodine Cleanup System
IEEE	Institute of Electrical and Electronic Engineers
IGSCC	intergranular stress corrosion cracking
IRM	intermediate range monitor
ISLH	inservice leak and hydrostatic
ITC	isothermal temperature coefficient

K-relay	control relay

LCS	Leakage Control System
LEFM	linear elastic fracture mechanics
LER	Licensee Event Report
LHGR	LINEAR HEAT GENERATION RATE
LHR	linear heat rate
LLS	low-low set
LOCA	loss-of-coolant accident
LOCV	loss of condenser vacuum
LOMFW	loss of main feedwater
LOP	loss of power
LOPS	loss of power start
LOVS	loss of voltage start
LPCI	low pressure coolant injection
LPCS	low pressure core spray
LPD	local power density
LPI	low pressure injection
LPRM	local power range monitor
LPSI	low pressure safety injection
LPSP	low power setpoint

(continued)

LPZ	low population zone
LSSS	limiting safety system settings
LTA	lead test assembly
LTOP	low temperature overpressure protection
MAPLHGR	maximum average planar linear heat generation rate
MAPFAC	MAPLHGR factor
$MAPFAC_f$	MAPLHGR factor, flow-dependent component
$MAPFAC_p$	MAPLHGR factor, power-dependent component
MCPR	MINIMUM CRITICAL POWER RATIO
MCR	main control room
MCREC	main control room environmental control
MFI	minimum flow interlock
MFIV	main feedwater isolation valve
MFLPD	maximum fraction of limiting power density
MFRV	main feedwater regulation valve
MFW	main feedwater
MG	motor-generator
MOC	middle of cycle
MSIS	main steam isolation signal
MSIV	main steam isolation valve
MSLB	main steam line break
MSSV	main steam safety valve
MTC	moderator temperature coefficient
NDT	nil-ductility temperature
NDTT	nil-ductility transition temperature
NI	nuclear instrument
NIS	Nuclear Instrumentation System
NMS	Neutron Monitoring System
NPSH	net positive suction head
NSSS	Nuclear Steam Supply System
ODCM	Offsite Dose Calculation Manual
OPDRV	operation with a potential for draining the reactor vessel
OTSG	once-through steam generator
PAM	post-accident monitoring
PCCGC	primary containment combustible gas control
PCI	primary containment isolation

(continued)

PCIV	primary containment isolation valve
PCHRS	Primary Containment Hydrogen Recombiner System
PCP	Process Control Program
PCPV	primary containment purge valve
PCT	peak cladding temperature
PDIL	power dependent insertion limit
PDL	power distribution limit
PF	position factor
PIP	position indication probe
PIV	pressure isolation valve
PORV	power operated relief valve
PPS	Plant Protective System
PRA	probabilistic risk assessment
PREACS	Pump Room Exhaust Air Cleanup System; Penetration Room Exhaust Air Cleanup System
PSW	plant service water
P/T	pressure and temperature
PTE	PHYSICS TEST exception
PTLR	PRESSURE AND TEMPERATURE LIMITS REPORT
QA	quality assurance
QPT	quadrant power tilt
QPTR	quadrant power tilt ratio
QS	quench spray
RACS	Rod Action Control System
RAOC	relaxed axial offset control
RAS	recirculation actuation signal
RB	reactor building
RBM	rod block monitor
RCCA	rod cluster control assembly
RCIC	reactor core isolation cooling
RCIS	Rod Control and Information System
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	Reactor Coolant System
REA	rod ejection accident
RHR	residual heat removal
RHRSW	residual heat removal service water
RMCS	Reactor Manual Control System
RPB	reactor pressure boundaries
RPC	rod pattern controller
RPCB	reactor power cutback

(continued)

RPIS	Rod Position Information System
RPS	Reactor Protection System
RPT	recirculation pump trip
RPV	reactor pressure vessel
RS	recirculation spray
RT	reference temperature
RT_{NDT}	nil-ductility reference temperature
RTCB	reactor trip circuit breaker
RTD	resistance temperature detector
RTM	reactor trip module
RTP	RATED THERMAL POWER
RTS	Reactor Trip System
RWCU	reactor water cleanup
RWE	rod withdrawal error
RWL	rod withdrawal limiter
RWM	rod worth minimizer
RWP	Radiation Work Permit
RWST	refueling water storage tank
RWT	refueling water tank
SAFDL	specified acceptable fuel design limits
SBCS	Steam Bypass Control System
SBO	station blackout
SBVS	Shield Building Ventilation System
SCAT	spray chemical addition tank
SCI	secondary containment isolation
SCR	silicon controlled rectifier
SDV	scram discharge volume
SDM	SHUTDOWN MARGIN
SER	Safety Evaluation Report
SFRCS	Steam and Feedwater Rupture Control System
SG	steam generator
SGTR	steam generator tube rupture
SGTS	Standby Gas Treatment System
SI	safety injection
SIAS	safety injection actuation signal
SIS	safety injection signal
SIT	safety injection tank
SJAE	steam jet air ejector
SL	Safety Limit
SLB	steam line break
SLC	standby liquid control
SLCS	Standby Liquid Control System
SPMS	Suppression Pool Makeup System
SRM	source range monitor

(continued)

S/RV	safety/relief valve
S/RVDL	safety/relief valve discharge line
SSPS	Solid State Protection System
SSW	standby service water
SWS	Service Water System
STE	special test exception
STS	Standard Technical Specifications
TADOT	trip actuating device operational test
TCV	turbine control valve
TIP	transversing incore probe
TLD	thermoluminescent dosimeter
TM/LP	thermal margin/low pressure
TS	Technical Specifications
TSV	turbine stop valve
UHS	Ultimate Heat Sink
VCT	volume control tank
VFTP	Ventilation Filter Testing Program
VHPT	variable high power trip
v/o	volume percent
VS	vendor specific
ZPMB	zero power mode bypass

NRC FORM 335 (2-89) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

(See instructions on the reverse)

1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.)

NUREG-1434
Vol. 3

2. TITLE AND SUBTITLE

Standard Technical Specifications
General Electric Plants, BWR/6

Bases (Sections 3.4-3.10)

Draft Report for Comment

3. DATE REPORT PUBLISHED

MONTH	YEAR
January	1991

4. FIN OR GRANT NUMBER

5. AUTHOR(S)

6. TYPE OF REPORT

Draft

7. PERIOD COVERED (Inclusive Dates)

8. PERFORMING ORGANIZATION – NAME AND ADDRESS (If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)

Division of Operational Events Assessment
Office of Nuclear Reactor Regulation
U.S. Nuclear Regualtory Commission
Washington, D.C. 20555

9. SPONSORING ORGANIZATION – NAME AND ADDRESS (If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address.)

Same as above

10. SUPPLEMENTARY NOTES

11. ABSTRACT (200 words or less)

This draft report documents the results of the NRC staff review of new Standard Technical Specifications (STS) proposed by the BWR Owners Group for the BWR/6 design. The new STS were developed based on the criteria in the interim Commission Policy Statement on Technical Specification Improvements for Nuclear Power Reactors, dated February 6, 1987. The new STS will be used as bases for individual nuclear power plant owners to develop improved plant-specific technical specifications. The NRC staff is issuing this draft new STS for a 30 working-day comment period. Following the comment period, the NRC staff will analyze comments received, finalize the new STS, and issue them for plant-specific implementation. This report contains three volumes. Volume 1 contains the Specifications for all sections of the new STS. Volume 2 contains the Bases for Sections 2.0 - 3.3 of the new STS and Volume 3 contains the Bases for Sections 3.4 - 3.10 of the new STS.

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)

Technical Specifications
General Electric
BWR/6

13. AVAILABILITY STATEMENT

Unlimited

14. SECURITY CLASSIFICATION

(This Page)

Unclassified

(This Report)

Unclassified

15. NUMBER OF PAGES

16. PRICE

NRC FORM 335 (2-89)