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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires, and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs).

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a stepback approach is used to establish an SL, such that the MCPR is not less than the limit specified in Specification 2.1.1.2 for Siemens Power Corporation fuel. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. Therefore, the fuel cladding SL is defined with a margin to the conditions that would produce onset of transition boiling (i.e., MCPR = 1.00). These conditions represent a significant departure from the condition intended by design for planned operation. The MCPR fuel cladding integrity SL ensures that during normal operation and during AOOs, at least 99.9% of the fuel rods in the core do not experience transition boiling.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the fuel design criterion that an MCPR limit is to be established, such that at least 99.9% of the fuel rods in the core would not be expected to experience the onset of transition boiling.

The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), in combination with the other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the MCPR limit.

2.1.1.1 Fuel Cladding Integrity

The use of the SPCB (Reference 4) correlation is valid for critical power calculations at pressures ≥ 571.4 psia and bundle mass fluxes > 0.087×10^6 lb/hr-ft^2 for SPCB. For operation at low pressures or low flows, the fuel cladding integrity SL is established by a limiting condition on core THERMAL POWER, with the following basis:

> Provided that the water level in the vessel downcomer is maintained above the top of the active fuel, natural circulation is sufficient to ensure a minimum bundle flow for all fuel assemblies that have a relatively high power and potentially can approach a critical heat flux condition. For the FANP Atrium 10 design, the minimum bundle flow is > 28×10^3 lb/hr. For Atrium-10 fuel design, the coolant minimum bundle flow and maximum area are such that the mass flux is always > $.25 \times 10^6$ lb/hr-ft^2. Full scale critical power test data taken from various SPC and GE fuel designs at pressures from 14.7 psia to 1400 psia indicate the fuel assembly critical power at 0.25×10^6 lb/hr-ft^2 is approximately 3.35 MWt. At 23% RTP, a bundle power of approximately 3.35 MWt corresponds to a bundle radial peaking factor of approximately 2.8, which is significantly higher than the expected peaking factor. Thus, a THERMAL POWER limit of 23% RTP for reactor pressures < 785 psig is conservative and for conditions of lesser power would remain the same.

2.1.1.2 MCPR

The MCPR SL ensures sufficient conservatism in the operating MCPR limit that, in the event of an AOO from the limiting condition of operation, at least 99.9% of the fuel rods in the core would be expected to avoid boiling transition. The margin between calculated boiling transition (i.e., MCPR = 1.00) and the MCPR SL is based on a detailed statistical procedure

(continued)

APPLICABLE SAFETY ANALYSES

2.1.1.2 MCPR (continued)

that considers the uncertainties in monitoring the core operating state. One specific uncertainty included in the SL is the uncertainty in the critical power correlation. References 2, 4 and 5 describe the methodology used in determining the MCPR SL.

The SPCB critical power correlation is based on a significant body of practical test data. As long as the core pressure and flow are within the range of validity of the correlation (refer to Section B 2.1.1.1), the assumed reactor conditions used in defining the SL introduce conservatism into the limit because bounding high radial power factors and bounding flat local peaking distributions are used to estimate the number of rods in boiling transition. These conservatisms and the inherent accuracy of the SPCB correlation provide a reasonable degree of assurance that during sustained operation at the MCPR SL there would be no transition boiling in the core. If boiling transition were to occur, there is reason to believe that the integrity of the fuel would not be compromised.

Significant test data accumulated by the NRC and private organizations indicate that the use of a boiling transition limitation to protect against cladding failure is a very conservative approach. Much of the data indicate that BWR fuel can survive for an extended period of time in an environment of boiling transition.

SPC ATRIUM-10 fuel is monitored using the SPCB Critical Power Correlation. The effects of channel bow on MCPR are explicitly included in the calculation of the MCPR SL. Explicit treatment of channel bow in the MCPR SL addresses the concerns of the NRC Bulletin No. 90-02 entitled "Loss of Thermal Margin Caused by Channel Box Bow."

Monitoring required for compliance with the MCPR SL is specified in LCO 3.2.2, Minimum Critical Power Ratio.

2.1.1.3 Reactor Vessel Water Level

During MODES 1 and 2 the reactor vessel water level is required to be above the top of the active fuel to provide core cooling capability. With fuel in the reactor vessel during periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level becomes < 2/3 of the core height.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.3 Reactor Vessel Water Level (continued)

The reactor vessel water level SL has been established at the top of the active irradiated fuel to provide a point that can be monitored and to also provide adequate margin for effective action.

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.

APPLICABILITY

SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.

SAFETY LIMIT VIOLATIONS

Exceeding an SL may cause fuel damage and create a potential for radioactive releases in excess of regulatory limits. Therefore, it is required to insert all insertable control rods and restore compliance with the SLs within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also ensures that the probability of an accident occurring during this period is minimal.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.

2. ANFB 524 (P)(A), Revision 2, "Critical Power Methodology for Boiling Water Reactors," Supplement 1 Revision 2 and Supplement 2, November 1990.

3. Deleted.

4. EMF-2209(P)(A), Revision 2, "SPCB Critical Power Correlation," Siemens Power Corporation, September 2003.

5. EMF-2158(P)(A), Rev. 0, "Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4 / MICROBURN-B2," October 1999.

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B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

BASES

BACKGROUND

The SDV vent and drain valves are normally open and discharge any accumulated water in the SDV to ensure that sufficient volume is available at all times to allow a complete scram. During a scram, the SDV vent and drain valves close to contain reactor water. The SDV is a volume of header piping that connects to each hydraulic control unit (HCU) and drains into an instrument volume. There are two SDVs (headers) and two instrument volumes, each receiving approximately one half of the control rod drive (CRD) discharges. The two instrument volumes are connected to a common drain line with two valves in series. Each header is connected to a common vent line with two valves in series. The header piping is sized to receive and contain all the water discharged by the CRDs during a scram. The design and functions of the SDV are described in Reference 1.

APPLICABLE SAFETY ANALYSES

The Design Basis Accident and transient analyses assume all of the control rods are capable of scramming. The acceptance criteria for the SDV vent and drain valves are that they operate automatically to:

a. Close during scram to limit the amount of reactor coolant discharged so that adequate core cooling is maintained and offsite and control room doses remain within regulatory limits; and

b. Open on scram reset to maintain the SDV vent and drain path open so that there is sufficient volume to accept the reactor coolant discharged during a scram.

Isolation of the SDV can also be accomplished by manual closure of the SDV valves. Additionally, the discharge of reactor coolant to the SDV can be terminated by scram reset or closure of the HCU manual isolation valves. For a bounding leakage case, the offsite and control room doses are well within regulatory limits, and adequate core cooling is maintained (Ref. 3). The SDV vent and drain valves allow continuous drainage of the SDV during normal plant operation

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

to ensure that the SDV has sufficient capacity to contain the reactor coolant discharge during a full core scram. To automatically ensure this capacity, a reactor scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") is initiated if the SDV water level in the instrument volume exceeds a specified setpoint. The setpoint is chosen so that all control rods are inserted before the SDV has insufficient volume to accept a full scram.

SDV vent and drain valves satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV vent and drain valves are required to be open to ensure the SDV is drained. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

APPLICABILITY

In MODES 1 and 2, scram may be required; therefore, the SDV vent and drain valves must be OPERABLE. In MODES 3 and 4, control rods are not able to be withdrawn (except as permitted by LCO 3.10.3 and LCO 3.10.4) since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate controls to ensure that only a single control rod can be withdrawn. Also, during MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Therefore, the SDV vent and drain valves are not required to be OPERABLE in these MODES since the reactor is subcritical and only one rod may be withdrawn and subject to scram.

ACTIONS

The ACTIONS table is modified by Note 1 indicating that a separate Condition entry is allowed for the SDV vent line and the SDV drain line. This is acceptable, since the

(continued)

BASES

ACTIONS (continued)

Required Actions for each Condition provide appropriate compensatory actions for each inoperable SDV line. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SDV lines are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS table is modified by a second note stating that a isolated line may be unisolated under administrative control to allow draining and venting of the SDV. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on high SDV level. This is acceptable since administrative controls ensure the valve can be closed quickly, if a scram occurs with the valve open.

A.1

When one SDV vent or drain valve is inoperable in one or more lines, the associated line must be isolated to contain the reactor coolant during a scram. The 7 day Completion Time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable and the line is not isolated. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion is not preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

B.1

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram.

The 8 hour Completion Time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and unlikelihood of significant CRD seal leakage.

C.1

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

(continued)

BASES

ACTIONS

C.1 (continued)

does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

During normal operation, the SDV vent and drain valves should be in the open position (except when performing SR 3.1.8.2) to allow for drainage of the SDV piping. Verifying that each valve is in the open position ensures that the SDV vent and drain valves will perform their intended functions during normal operation. This SR does not require any testing or valve manipulation; rather, it involves verification that the valves are in the correct position.

The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation, which ensure correct valve positions.

SR 3.1.8.2

During a scram, the SDV vent and drain valves should close to contain the reactor water discharged to the SDV piping. Cycling each valve through its complete range of motion (closed and open) ensures that the valve will function properly during a scram. The 92 day Frequency is based on operating experience and takes into account the level of redundancy in the system design.

SR 3.1.8.3

SR 3.1.8.3 is an integrated test of the SDV vent and drain valves to verify total system performance. After receipt of a simulated or actual scram signal, the closure of the SDV vent and drain valves is verified. The closure time of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.3 (continued)

30 seconds after receipt of a scram signal is based on the bounding leakage case evaluated in the accident analysis based on the requirements of Reference 2. Similarly, after receipt of a simulated or actual scram reset signal, the opening of the SDV vent and drain valves is verified. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1 and the scram time testing of control rods in LCO 3.1.3 overlap this Surveillance to provide complete testing of the assumed safety function. The 24 month Frequency is based on the need to perform portions of this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 4.6.
2. 10 CFR 50.67
3. NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," August 1981.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
5. TSTF-404-A, Rev. 0.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

BASES

BACKGROUND

The APLHGR is a measure of the average LHGR of all the fuel rods in a fuel assembly at any axial location. Limits on the APLHGR are specified to ensure that limits specified in 10 CFR 50.46 are not exceeded during the postulated design basis loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

SPC performed LOCA calculations for the SPC ATRIUM™-10 fuel design. The analytical methods and assumptions used in evaluating the fuel design limits from 10 CFR 50.46 are presented in References 3, 4, 5, and 6 for the SPC analysis. The analytical methods and assumptions used in evaluating Design Basis Accidents (DBAs) that determine the APLHGR Limits are presented in References 3 through 9.

LOCA analyses are performed to ensure that the APLHGR limits are adequate to meet the Peak Cladding Temperature (PCT), maximum cladding oxidation, and maximum hydrogen generation limits of 10 CFR 50.46. The analyses are performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A complete discussion of the analysis codes are provided in References 3, 4, 5, and 6 for the SPC analysis. The PCT following a postulated LOCA is a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within the assembly.

APLHGR limits are developed as a function of fuel type and exposure. The SPC analysis is valid for full cores of ATRIUM™-10 fuel. The SPC LOCA analyses also consider several alternate operating modes in the development of the APLHGR limits (e.g., Maximum Extended Load Line Limit Analysis (MELLLA), Suppression Pool Cooling Mode, and Single Loop Operation (SLO)). LOCA analyses were performed for the regions of the power/ flow map bounded by the rod line that runs through 100% RTP and maximum core flow and the upper boundary of the MELLLA region. The MELLLA region is analyzed to determine whether an APLHGR multiplier as a function of core flow is required. The results of the analysis demonstrate the PCTs are within the 10 CFR 50.46 limit, and that APLHGR multipliers as a function of core flow are not required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SPC LOCA analyses consider the delay in Low Pressure Coolant Injection (LPCI) availability when the unit is operating in the Suppression Pool Cooling Mode. The delay in LPCI availability is due to the time required to realign valves from the Suppression Pool Cooling Mode to the LPCI mode. The results of the analyses demonstrate that the PCTs are within the 10 CFR 50.46 limit.

Finally, the SPC LOCA analyses were performed for Single-Loop Operation. The results of the SPC analysis for ATRIUM™-10 fuel shows that an APLHGR limit which is 0.8 times the two-loop APLHGR limit meets the 10 CFR 50.46 acceptance criteria, and that the PCT is less than the limiting two-loop PCT.

The APLHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 10).

LCO

The APLHGR limits specified in the COLR are the result of the DBA analyses.

APPLICABILITY

The APLHGR limits are primarily derived from LOCA analyses that are assumed to occur at high power levels. Design calculations and operating experience have shown that as power is reduced, the margin to the required APLHGR limits increases. At THERMAL POWER levels < 23% RTP, the reactor is operating with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

If any APLHGR exceeds the required limits, an assumption regarding an initial condition of the DBA may not be met. Therefore, prompt action should be taken to restore the APLHGR(s) to within the required limits such that the plant operates within analyzed conditions. The 2 hour Completion Time is sufficient to restore the APLHGR(s) to within its limits and is acceptable based on the low probability of a DBA occurring simultaneously with the APLHGR out of specification.

(continued)

BASES

ACTIONS (continued)

B.1

If the APLHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 23% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 23% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 24 hours after THERMAL POWER is ≥ 23% RTP and then every 24 hours thereafter. Additionally, APLHGRs must be calculated prior to exceeding 44% RTP unless performed in the previous 24 hours. APLHGRs are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 24 hour allowance after THERMAL POWER ≥ 23% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels and because the APLHGRs must be calculated prior to exceeding 44% RTP.

REFERENCES

1. Not Used

2. Not Used

3. EMF-2361(P)(A), "EXEM BWR-2000 ECCS Evaluation Model," Framatome ANP.

4. EMF-2292(P)(A) Revision 0, "ATRIUM™-10: Appendix K Spray Heat Transfer Coefficients."

5. XN-CC-33(P)(A) Revision 1, "HUXY: A Generalized Multirod Heatup Code with 10CFR50 Appendix K Heatup Option Users Manual," November 1975.

(continued)

BASES

REFERENCES (continued)

6. XN-NF-80-19(P)(A), Volumes 2, 2A, 2B, and 2C "Exxon Nuclear Methodology for Boiling Water Reactors: EXEM BWR ECCS Evaluation Model," September 1982.

7. FSAR, Chapter 4.

8. FSAR, Chapter 6.

9. FSAR, Chapter 15.

10. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of boiling transition to the actual fuel assembly power. The MCPR Safety Limit (SL) is set such that 99.9% of the fuel rods avoid boiling transition if the limit is not violated (refer to the Bases for SL 2.1.1.2). The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences (AOOs). Although fuel damage does not necessarily occur if a fuel rod actually experienced boiling transition (Ref. 1), the critical power at which boiling transition is calculated to occur has been adopted as a fuel design criterion.

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, flow, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the AOOs to establish the operating limit MCPR are presented in References 2 through 10. To ensure that the MCPR SL is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the largest reduction in critical power ratio (CPR). The types of transients evaluated are loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR (ΔCPR). When the largest ΔCPR is added to the MCPR SL, the required operating limit MCPR is obtained.

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency These analyses may also consider other

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

combinations of plant conditions (i.e., control rod scram speed, bypass valve performance, EOC-RPT, cycle exposure, etc.). Flow dependent MCPR limits are determined by analysis of slow flow runout transients.

The MCPR satisfies Criterion 2 of the NRC Policy Statement (Ref. 11).

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the flow dependent MCPR and power dependent MCPR limits.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 23% RTP, the reactor is operating at a minimum recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 23% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs. Studies of the variation of limiting transient behavior have been performed over the range of power and flow conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as power is reduced to 23% RTP. This trend is expected to continue to the 5% to 15% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 23% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR is outside the required limits, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limits such that the plant remains operating within

(continued)

BASES

ACTIONS

A.1 (continued)

analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 23% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 23% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 24 hours after THERMAL POWER is ≥ 23% RTP and then every 24 hours thereafter. Additionally, MCPR must be calculated prior to exceeding 44% RTP unless performed in the previous 24 hours. MCPR is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 24 hour allowance after THERMAL POWER ≥ 23% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels and because the MCPR must be calculated prior to exceeding 44% RTP.

SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram time performance, it must be demonstrated that the specific scram time is consistent with those used in the transient analysis. SR 3.2.2.2 compares the average measured scram times to the assumed scram times documented in the COLR. The COLR contains a table of scram times based on the LCO 3.1.4, "Control Rod Scram Times" and the realistic scram times, both of which are used in the transient analysis. If the average measured scram times are greater than the realistic scram times then the MCPR operating limits corresponding to the Maximum Allowable Average Scram Insertion Time must be implemented.

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SURVEILLANCE REQUIREMENTS

SR 3.2.2.2 (continued)

Determining MCPR operating limits based on interpolation between scram insertion times is not permitted. The average measured scram times and corresponding MCPR operating limit must be determined once within 72 hours after each set of scram time tests required by SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3 and SR 3.1.4.4 because the effective scram times may change during the cycle. The 72 hour Completion Time is acceptable due to the relatively minor changes in average measured scram times expected during the fuel cycle.

REFERENCES

1. NUREG-0562, June 1979.

2. XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, "Exxon Nuclear Methodology for Boiling Water Reactors," Exxon Nuclear Company, March 1983.

3. XN-NF-80-19(P)(A) Volume 3, Revision 2, "Exxon Nuclear Methodology for Boiling Water Reactors, THERMEX: Thermal Limits Methodology Summary Description," Exxon Nuclear Company, January 1987.

4. ANF-913(P)(A) Volume 1, Revision 1 and Volume 1 Supplements 2, 3, and 4, "COTRANSA2: A Computer Program for Boiling Water Reactor Transient Analyses," Advanced Nuclear Fuels Corporation, August 1990.

5. XN-NF-80-19 (P)(A), Volume 4, Revision 1, "Exxon Nuclear Methodology for Boiling Water Reactors: Application of the ENC Methodology to BWR Reloads," Exxon Nuclear Company, June 1986.

6. NE-092-001, Revision 1, "Susquehanna Steam Electric Station Units 1 & 2: Licensing Topical Report for Power Uprate with Increased Core Flow," December 1992, and NRC Approval Letter: Letter from T. E. Murley (NRC) to R. G. Byram (PP&L), "Licensing Topical Report for Power Uprate With Increased Core Flow, Revision 0, Susquehanna Steam Electric Station, Units 1 and 2 (PLA-3788) (TAC Nos. M83426 and M83427)," November 30, 1993.

7. EMF-2209(P)(A), Revision 2, "SPCB Critical Power Correlation," Siemens Power Corporation, September 2003.

(continued)

Reference (continued)

8. XN-NF-79-71(P)(A) Revision 2, Supplements 1, 2, and 3, "Exxon Nuclear Plant Transient Methodology for Boiling Water Reactors," March 1986.

9. XN-NF-84-105(P)(A), Volume 1 and Volume 1 Supplements 1 and 2, "XCOBRA-T: A Computer Code for BWR Transient Thermal-Hydraulic Core Analysis," February 1987.

10. ANF-1358(P)(A) Revision 3, "The Loss of Feedwater Heating Transient in Boiling Water Reactors," Advanced Nuclear Fuels Corporation, September 2005.

11. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

BASES

BACKGROUND

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. Limits on LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation. Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure, or inability to cool the fuel does not occur during the normal operations identified in Reference 1.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel system design are presented in References 1, 2, 3, and 4. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection system) that fuel damage will not result in the release of radioactive materials in excess of regulatory limits. The mechanisms that could cause fuel damage during operational transients and that are considered in fuel evaluations are:

a. Rupture of the fuel rod cladding caused by strain from the relative expansion of the UO_2 pellet; and

b. Severe overheating of the fuel rod cladding caused by inadequate cooling.

A value of 1% plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur (Ref. 3).

Fuel design evaluations have been performed and demonstrate that the 1% fuel cladding plastic strain design limit is not exceeded during continuous operation with LHGRs up to the operating limit specified in the COLR. A separate evaluation was performed to determine the limits of LHGR during anticipated operational occurrences. This limit, Protection Against Power Transients (PAPT), defined in reference 4, provides the acceptance criteria for LHGRs calculated in evaluation of the AOOs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 5).

LCO

The LHGR is a basic assumption in the fuel design analysis. The fuel has been designed to operate at rated core power with sufficient design margin to the LHGR calculated to cause a 1% fuel cladding plastic strain. The operating limit to accomplish this objective is specified in the COLR.

APPLICABILITY

The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 23% RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at ≥ 23% RTP.

ACTIONS

A.1

If any LHGR exceeds its required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action should be taken to restore the LHGR(s) to within its required limits such that the plant is operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LHGR out of specification.

B.1

If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER is reduced to < 23% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 23% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The LHGR is required to be initially calculated within 24 hours after THERMAL POWER is ≥ 23% RTP and then every 24 hours thereafter. Additionally, LHGRs must be calculated prior to exceeding 44% RTP unless performed in the previous 24 hours. The LHGR is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slow changes in power distribution during normal operation. The 24 hour allowance after THERMAL POWER ≥ 23% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels and because the LHGRs must be calculated prior to exceeding 44% RTP.

REFERENCES

1. FSAR, Section 4.

2. FSAR, Section 5.

3. NUREG-0800, Section II.A.2(g), Revision 2, July 1981.

4. ANF-89-98(P)(A) Revision 1 and Revision 1 Supplement 1, "Generic Mechanical Design Criteria for BWR Fuel Design," Advanced Nuclear Fuels Corporation, May 1995.

5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

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

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

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

APPLICABLE SAFETY ANALYSES

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

Jet pumps satisfy Criterion 2 of the NRC Policy Statement (Ref. 4).

LCO

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

APPLICABILITY

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

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

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding during a design basis LOCA. If one or more of the jet pumps are inoperable, the

(continued)

BASES

ACTIONS

A.1 (continued)

plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. With no forced recirculation flow, stresses on jet pump assemblies are significantly reduced. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 2 and 3). Each recirculation loop must satisfy two of the performance criteria provided. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns", engineering judgement of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (loop

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

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

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

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

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

This SR is modified by two Notes. If this SR has not been performed in the previous 24 hours at the time an idle recirculation loop is restored to service, Note 1 allows 4 hours after the idle recirculation loop is in operation before the SR must be completed because these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions and complete data collection and evaluation.

Note 2 allows deferring completion of this SR until 24 hours after THERMAL POWER is greater than 23% of RTP. During low flow conditions, jet pump noise approaches the threshold

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data.

REFERENCES

1. FSAR, Section 6.3.
2. GE Service Information Letter No. 330, June 9, 1990.
3. NUREG/CR-3052, November 1984.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. There are a total of 16 S/RVs of which any 14 are required to be OPERABLE. 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 valve opens when steam pressure at the valve inlet overcomes the spring force holding the valve closed. This satisfies the Code requirement.

Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. Six S/RVs also serve as the Automatic Depressurization System (ADS) valves. The ADS requirements are specified in LCO 3.5.1, "ECCS—Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, 14 of the 16 S/RVs are assumed to operate in the safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the Design Basis Event.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

S/RVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

The safety function of 14 of the 16 S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

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

Operation with fewer valves OPERABLE than specified, or with setpoints outside the 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, all required S/RVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

In MODE 4 reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed

(continued)

BASES

APPLICABILITY (continued)

operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.

ACTIONS

A.1 and A.2

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

SURVEILLANCE REQUIREMENT

SR 3.4.3.1

The Surveillance requires that the required S/RVs will open at the pressures assumed in the safety analysis of Reference 1. The demonstration of the S/RV safe lift settings must be performed during shutdown, since this is a bench test, to be done in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The S/RV setpoint is ±3% of the nominal setpoint for OPERABILITY. Requirements for accelerated testing are established in accordance with the Inservice Test Program. Any of the 16 S/RVs, identified in this Surveillance Requirement, with their associated setpoints, can be designated as the 14 required S/RVs. This maintains the assumptions in the overpressure analysis.

A Note is provided to allow up to two of the required 14 S/RVs to be physically replaced with S/RVs with lower setpoints until the next refueling outage. This provides operational flexibility which maintains the assumptions in the over-pressure analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

The Frequency of this Surveillance is established in accordance with the Inservice Testing Program.

REFERENCES

1. FSAR, Section 5.2.2.1.4.
2. FSAR, Section 15.
3. ASME Operation and Maintenance Code.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

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 pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

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

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

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

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

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted,
as necessary, based on the evaluation findings and the recommendations of RG 1.99, "Radiation Embrittlement of Reactor Vessel Materials (Ref. 5). The calculations to determine neutron fluence will be developed using the BWRVIP RAMA code methodology, which is NRC approved and meets the intent of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence" (Ref. 11). See FSAR Section 4.1.4.5 for determining fluence (Ref. 12).

(continued)

BASES

BACKGROUND (continued)

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

The heatup curve used to develop the P/T limit curve composite represents a different set of restrictions than the cooldown curve used to develop the P/T limit curve composite because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

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

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. Reference 7 establishes the methodology for determining the P/T limits. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement (Ref. 8).

The Effective Full Power Years (EFPY) shown on the curves are approximations of the ratio of the energy that has been and is anticipated to be generated in a year to the energy that could have been generated if the unit ran at original thermal power rating of 3293 MWT for the entire year. These values are based on fluence limits that are not to be exceeded.

(continued)

BASES (continued)

LCO

The elements of this LCO are:

a. RCS pressure and temperature are to the right of the applicable curves specified in Figures 3.4.10-1 through 3.4.10-3 and within the applicable heat-up or cool down rate specified in SR 3.4.10.1 during RCS heatup, cooldown, and inservice leak and hydrostatic testing;

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is ≤ 145°F during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is ≤ 50°F during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;

d. RCS pressure and temperature are to the right of the criticality limits specified in Figure 3.4.10-3 prior to achieving criticality; and

e. The reactor vessel flange and the head flange temperatures are ≥ 70°F when tensioning the reactor vessel head bolting studs.

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

The P/T limit composite curves are calculated using the worst case of material properties, stresses, and temperature change rates anticipated under all heatup and cooldown conditions. The design calculations account for the reactor coolant fluid temperature impact on the inner wall of the vessel and the temperature gradients through the vessel wall. Because these fluid temperatures drive the vessel wall temperature gradient, monitoring reactor coolant temperature provides a conservative method of ensuring the P/T limits are not exceeded. Proper monitoring of vessel temperatures to assure compliance with brittle fracture temperature limits and vessel thermal stress limits during normal heatup and cooldown, and during inservice leakage and hydrostatic testing, is established in PPL Calculation EC 062-0573 (Ref. 9). For P/T curves A, B, and C, the bottom head drain line coolant temperature should be monitored and maintained to the right of the most limiting curve.

(continued)

BASES

LCO (continued)

Curve A must be used for any ASME Section III Design Hydrostatic Tests performed at unsaturated reactor conditions. Curve A may also be used for ASME Section XI inservice leakage and hydrostatic testing when heatup and cooldown rates can be limited to 20°F in a one-hour period. Curve A is based on pressure stresses only. Thermal stresses are assumed to be insignificant. Therefore, heatup and cooldown rates are limited to 20°F in a one-hour period when using Curve A to ensure minimal thermal stresses. The recirculation loop suction line temperatures should be monitored to determine the temperature change rate.

Curves B and C are to be used for non-nuclear and nuclear heatup and cooldown, respectively. In addition, Curve B may be used for ASME Section XI inservice leakage and hydrostatic testing, but not for ASME Section III Design Hydrostatic Tests performed at unsaturated reactor conditions. Heatup and cooldown rates are limited to 100°F in a one-hour period when using Curves B and C. This limits the thermal gradient through the vessel wall, which is used to calculate the thermal stresses in the vessel wall. Thus, the LCO for the rate of coolant temperature change limits the thermal stresses and ensures the validity of the P/T curves. The vessel belt-line fracture analysis assumes a 100°F/hr coolant heatup or cooldown rate in the beltline area. The 100°F limit in a one-hour period applies to the coolant in the beltline region, and takes into account the thermal inertia of the vessel wall. Steam dome saturation temperature (T_{SAT}), as derived from steam dome pressure, should be monitored to determine the beltline temperature change rate at temperatures above 212°F. At temperatures below 212°F, the recirculation loop suction line temperatures should be monitored.

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

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

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

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

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

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

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

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

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

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

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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

C.1 and C.2

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

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 200°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

Verification that operation is within limits (i.e., to the right of the applicable curves in Figures 3.4.10-1 through 3.4.10-3) is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits a reasonable time for assessment and correction of minor deviations.

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

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

Notes to the acceptance criteria for heatup and cooldown rates ensure that more restrictive limits are applicable when the P/T limits associated with hydrostatic and inservice testing are being applied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.10.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits (i.e., to the right of the criticality curve in Figure 3.4.10-3) before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of reactor criticality. Although no Surveillance Frequency is specified, the requirements of SR 3.4.10.2 must be met at all times when the reactor is critical.

SR 3.4.10.3 and SR 3.4.10.4

Differential temperatures within the applicable limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 10) are satisfied.

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

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.10.4 is to compare the temperatures of the operating recirculation loop and the idle loop. If both loops are idle, compare the temperature difference between the reactor coolant within the idle loop to be started and coolant in the reactor vessel.

SR 3.4.10.3 has been modified by a Note that requires the Surveillance to be performed only in MODES 1, 2, 3, and 4. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. The Note also states the SR is only required to be met during a recirculation pump start-up, because this is when the stresses occur.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.10.5 and SR 3.4.10.6

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increases in THERMAL POWER or recirculation loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in power or flow rate provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.10.6 is to compare the temperatures of the operating recirculation loop and the idle loop.

Plant specific startup test data has determined that the bottom head is not subject to temperature stratification at power levels > 27% of RTP and with single loop flow rate ≥ 21,320 gpm (50% of rated loop flow). Therefore, SR 3.4.10.5 and SR 3.4.10.6 have been modified by a Note that requires the Surveillance to be met only under these conditions. The Note for SR 3.4.10.6 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop can not be introduced into the remainder of the Reactor Coolant System.

SR 3.4.10.7, SR 3.4.10.8, and SR 3.4.10.9

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

The flange temperatures must be verified to be above the limits 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 ≤ 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 ≤ 100°F, monitoring of the flange temperature is required every 12 hours to ensure the temperature is within the specified limits.

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

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G.
3. ASTM E 185-73
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. NEDO-21778-A, December 1978.
8. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
9. PPL Calculation EC-062-0573, "Study to Support the Bases Section of Technical Specification 3.4.10."
10. FSAR, Section 15.4.4.
11. Regulatory Guide 1.190, March 2001.
12 FSAR, Section 4.1.4.5.

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The RHRSW System is designed to provide cooling water for the Residual Heat Removal (RHR) System heat exchangers, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RHRSW System is operated whenever the RHR heat exchangers are required to operate in the shutdown cooling mode or in the suppression pool cooling or spray mode of the RHR System.

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, one pump, a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to maintain safe shutdown conditions. The two subsystems are separated so that failure of one subsystem will not affect the OPERABILITY of the other subsystem. One Unit 1 RHRSW subsystem and the associated (same division) Unit 2 RHRSW subsystem constitute a single RHRSW loop. The two RHRSW pumps in a loop can each, independently, be aligned to either Unit's heat exchanger. The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in the FSAR, Section 9.2.6, Reference 1.

Cooling water is pumped by the RHRSW pumps from the UHS through the tube side of the RHR heat exchangers. After removing heat from the RHRSW heat exchanger, the water is discharged to the spray pond (UHS) by way of the UHS return loops. The UHS return loops direct the return flow to a network of sprays that dissipate the heat to the atmosphere or directly to the UHS via a bypass header.

The system is initiated manually from the control room except for the spray array bypass manual valves that are operated locally in the event of a failure of the spray array bypass valves. The system can be started any time the LOCA signal is manually overridden or clears.

(continued)

BASES

BACKGROUND (continued)

The ultimate heat sink (UHS) system is composed of approximately 3,300,000 cubic foot spray pond and associated piping and spray risers. Each UHS return loop contains a bypass line, a large spray array and a small spray array. The purpose of the UHS is to provide both a suction source of water and a return path for the RHRSW and ESW systems. The function of the UHS is to provide water to the RHRSW and ESW systems at a temperature less than the 97°F design temperature of the RHRSW and ESW systems. UHS temperature is maintained less than the design temperature by introducing the hot return fluid from the RHRSW and ESW systems into the spray loops and relying on spray cooling to maintain temperature. The UHS is designed to supply the RHRSW and ESW systems with all the cooling capacity required during a combination LOCA/LOOP for thirty days without fluid addition. The UHS is described in the FSAR, Section 9.2.7 (Reference 1).

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the RHRSW System to support long term cooling of the reactor or primary containment is discussed in the FSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). These analyses explicitly assume that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The safety analyses for long term cooling were performed for various RHRSW and UHS configurations combinations of RHR System failures. As discussed in the FSAR, Section 6.2.2 (Ref. 2) for these analyses, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is required. The maximum suppression chamber water temperature and pressure are analyzed to be below the design temperature of 220°F and maximum allowable pressure of 53 psig.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The UHS design takes into account the cooling efficiency of the spray arrays and the evaporation losses during design basis environmental conditions. The spray array bypass header provides the flow path for the ESW and RHRSW system to keep the spray array headers from freezing. The small and/or large spray arrays are placed in service to dissipate heat returning from the plant. The UHS return header is comprised of the spray array bypass header, the large spray array, and the small spray array.

The spray array bypass header is capable of passing full flow from the RHRSW and ESW systems in each loop. The large spray array is capable of passing full flow from the RHRSW and ESW systems in each loop. The small spray array supports heat dissipation when low system flows are required.

The RHRSW System, together with the UHS, satisfy Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

Two RHRSW subsystems are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming the worst case single active failure occurs coincident with the loss of offsite power.

An RHRSW subsystem is considered OPERABLE when:

a. One pump is OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the UHS and transferring the water to the RHR heat exchanger and returning it to the UHS at the assumed flow rate, and

c. An OPERABLE UHS.

The OPERABILITY of the UHS is based on having a minimum water level at the overflow weir of 678 feet 1 inch above mean sea level and a maximum water temperature of 85°F; unless either unit is in MODE 3. If a unit enters MODE 3, the time of entrance into this condition determines the appropriate maximum ultimate heat sink fluid temperature. If the earliest unit to enter MODE 3 has been in that condition for less than twelve (12) hours, the peak temperature to maintain OPERABILITY of the ultimate heat sink remains at 85°F. If either unit has been in MODE 3 for more than twelve (12) hours but less than twenty-four (24) hours, the OPERABILITY temperature of the ultimate heat sink becomes 87°F. If either unit has been in MODE 3 for twenty-four (24) hours or more, the OPERABILITY temperature of the ultimate heat sink becomes 88°F.

(continued)

BASES

LCO (continued)

In addition, the OPERABILITY of the UHS is based on having sufficient spray capacity in the UHS return loops. Sufficient spray capacity is defined as one large and one small spray array in one loop.

This OPERABILITY definition is supported by analysis and evaluations performed in accordance with the guidance given in Regulatory Guide 1.27.

APPLICABILITY

In MODES 1, 2, and 3, the RHRSW System and the UHS are required to be OPERABLE to support the OPERABILITY of the RHR System for primary containment cooling (LCO 3.6.2.3, "Residual Heat Removal (RHR) Suppression Pool Cooling," and LCO 3.6.2.4, "Residual Heat Removal (RHR) Suppression Pool Spray") and decay heat removal (LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"). The Applicability is therefore consistent with the requirements of these systems.

In MODES 4 and 5, the OPERABILITY requirements of the RHRSW System are determined by the RHR shutdown cooling subsystem(s) it supports (LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR) - High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR) - Low Water Level").

In MODES 4 and 5, the OPERABILITY requirements of the UHS is determined by the systems it supports.

ACTIONS

The ACTIONS are modified by a Note indicating that the applicable Conditions of LCO 3.4.8, be entered and Required Actions taken if the inoperable RHRSW subsystem results in inoperable RHR shutdown cooling (SDC) (i.e., both the Unit 1 and Unit 2 RHRSW pumps in a loop are inoperable resulting in the associated RHR SDC system being inoperable). This is an exception to LCO 3.0.6 because the Required Actions of LCO 3.7.1 do not adequately compensate for the loss of RHR SDC Function (LCO 3.4.8).

Condition A is modified by a separate note to allow separate Condition entry for each valve. This is acceptable since the Required Action for this Condition provide appropriate compensatory actions.

(continued)

BASES

ACTIONS (continued)

A.1

With one spray loop bypass valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return loop. As a result, the associated RHRSW subsystem must be declared inoperable.

With one spray loop bypass valve not capable of being opened on demand, a return flow path is not available. As a result, the associated RHRSW subsystems must be declared inoperable.

With one spray array bypass manual valve not capable of being closed, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return path if the spray array bypass valve fails to close. As a result, the associated RHRSW subsystems must be declared inoperable.

With one spray array bypass manual valve not open, a return flow path is not available. As a result, the associated RHRSW subsystems must be declared inoperable.

With one large spray array valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the full required spray cooling capability of the affected UHS return path. With one large spray array valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the small spray array when loop flows are low as the required spray nozzle pressure is not achievable for the small spray array. As a result, the associated RHRSW subsystems must be declared inoperable.

With one small spray array valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return path for low loop flow rates. For a single failure of the large spray array valve in the closed position, design bases LOCA/LOOP calculations assume that flow is reduced on the affected loop within 3 hours after the event to allow use of the small spray array. With one small spray array valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the large spray array for a flow path as the required nozzle pressure is not achievable for the large spray array. As a result, the associated RHRSW subsystems must be declared inoperable.

(continued)

BASES

ACTIONS (continued)

With any UHS return path valve listed in Tables 3.7.1-1, 3.7.1-2, or 3.7.1-3 inoperable, the UHS return path is no longer single failure proof.

For combinations of inoperable valves in the same loop, the UHS spray capacity needed to support the OPERABILITY of the associated Unit 1 and Unit 2 RHRSW subsystems is affected. As a result, the associated RHRSW subsystems must be declared inoperable.

The 8-hour completion time to establish the flow path provides sufficient time to open a path and de-energize the appropriate valve in the open position.

The 72-hour completion time is based on the fact that, although adequate UHS spray loop capability exists during this time period, both units are affected and an additional single failure results in a system configuration that will not meet design basis accident requirements.

If an additional RHRSW subsystem on either Unit is inoperable, cooling capacity less than the minimum required for response to a design basis event would exist. Therefore, an 8-hour Completion Time is appropriate. The 8-hour Completion Time provides sufficient time to restore inoperable equipment and there is a low probability that a design basis event would occur during this period.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if one Unit 2 RHRSW subsystem is inoperable. Although designated and operated as a unitized system, the associated Unit 1 subsystem is directly connected to a common header which can supply the associated RHR heat exchanger in either unit. The Unit 1 subsystems are considered capable of supporting Unit 2 RHRSW subsystem when the Unit 1 subsystem is OPERABLE and can provide the assumed flow to the Unit 2 heat exchanger. A Completion time of 72 hours, when one Unit 1 RHRSW subsystem is not capable of supporting the Unit 2 RHRSW subsystems, is allowed to restore the Unit 2 RHRSW subsystem to OPERABLE status. In this configuration, the remaining OPERABLE Unit 2 RHRSW subsystem is adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE RHRSW subsystem

(continued)

BASES

ACTIONS

B.1 (continued

could result in loss of RHRSW function. The Completion Time is based on the redundant RHRSW capabilities afforded by the OPERABLE subsystem and the low probability of an event occurring requiring RHRSW during this period.

With one RHRSW subsystem inoperable, and both of the Unit 1 RHRSW subsystems capable of supporting their respective Unit 2 RHRSW subsystems, the design basis cooling capacity for both units can still be maintained even considering a single active failure. However, the configuration does reduce the overall reliability of the RHRSW System. Therefore, provided both of the Unit 1 subsystems remain capable of supporting their respective Unit 2 RHRSW subsystems, the inoperable RHRSW subsystem must be restored to OPERABLE status within 7 days. The 7-day Completion Time is based on the remaining RHRSW System heat removal capability.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if both Unit 2 RHRSW subsystems are inoperable. Although designated and operated as a unitized system, the associated Unit 1 subsystem is directly connected to a common header which can supply the associated RHR heat exchanger in either unit. With both Unit 2 RHRSW subsystems inoperable, the RHRSW system is still capable of performing its intended design function. However, the loss of an additional RHRSW subsystem on Unit 1 results in the cooling capacity to be less than the minimum required for response to a design basis event. Therefore, the 8-hour Completion Time is appropriate. The 8-hour Completion Time for restoring one RHRSW subsystem to OPERABLE status, is based on the Completion Times provided for the RHR suppression pool spray function.

With both Unit 2 RHRSW subsystems inoperable, and both of the Unit 1 RHRSW subsystems capable of supporting their respective Unit 2 RHRSW subsystem, if no additional failures occur which impact the RHRSW System, the remaining OPERABLE Unit 1 subsystems and flow paths provide adequate heat removal capacity following a design basis LOCA. However, capability for this alignment is not assumed in long term containment response analysis and an additional single failure in the RHRSW System could reduce the system capacity below that assumed in the safety analysis.

(continued)

BASES

ACTIONS

C.1 (continued)

Therefore, continued operation is permitted only for a limited time. One inoperable subsystem is required to be restored to OPERABLE status within 72 hours. The 72 hour Completion Time for restoring one inoperable RHRSW subsystem to OPERABLE status is based on the fact that the alternate loop is capable of providing the required cooling capability during this time period.

D.1 and D.2

If the RHRSW subsystems cannot be restored to OPERABLE status within the associated Completion Times, or the UHS is determined to be inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the water level to be sufficient for the proper operation of the RHRSW pumps (net positive suction head and pump vortexing are considered in determining this limit). The 12 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.2

Verification of the UHS temperature, which is the arithmetical average of the UHS temperature near the surface, middle and bottom levels, ensures that the heat removal capability of the ESW and RHRSW Systems are within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.3

Verifying the correct alignment for each manual, power operated, and automatic valve in each RHRSW subsystem flow path provides assurance that the proper flow paths will exist for RHRSW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be realigned to its accident position. This is acceptable because the RHRSW System is a manually initiated system.

This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31-day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.1.4

The UHS spray array bypass valves are required to actuate to the closed position for the UHS to perform its design function. These valves receive an automatic signal to open upon emergency service water (ESW) or residual heat removal service water (RHRSW) system pump start and are required to be operated from the control room or the remote shutdown panel. A spray bypass valve is considered to be inoperable when it cannot be closed on demand. Failure of the spray bypass valve to close on demand puts the UHS at risk to exceed its design temperature. The failure of the spray bypass valve to open on demand makes one return path unavailable, and therefore the associated RHRSW subsystems must be declared inoperable. This SR demonstrates that the valves will move to their required positions when required. The 92-day Test Frequency is based upon engineering judgement and operating/testing history that indicates this frequency gives adequate assurance that the valves will move to their required positions when required.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.5

The UHS return header large spray array valves are required to open in order for the UHS to perform its design function. These valves are manually actuated from either the control room or the remote shutdown panel, under station operating procedure, when the RHRSW system is required to remove energy from the reactor vessel or suppression pool. This SR demonstrates that the valves will move to their required positions when required. The 92-day Test Frequency is based upon engineering judgement and operating/testing history that indicates this frequency gives adequate assurance that the valves will move to their required positions when required.

SR 3.7.1.6

The small spray array valves HV-01224A2 and B2 are required to operate in order for the UHS to perform its design function. These valves are manually actuated from the control room or the remote shutdown panel, under station operating procedure, when the RHRSW system is required to remove energy from the reactor vessel or suppression pool. This SR demonstrates that the valves will move to their required positions when required. The
92-day Test Frequency is based upon engineering judgment and operating/testing history that indicates this frequency gives adequate assurance that the valves will move to their required positions when required.

SR 3.7.1.7

The spray array bypass manual valves 012287A and B are required to operate in the event of a failure of the spray array bypass valves to close in order for the UHS to perform its design function.

REFERENCES

1. FSAR, Section 9.2.
2. FSAR, Chapter 6.
3. FSAR, Chapter 15.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The full bypass capacity of the system is approximately 23% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of five valves connected to the main steam lines between the main steam isolation valves and the turbine stop valve bypass valve chest. Each of these five valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the FSAR, Section 7.7.1.5 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct 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 has two modes of operation. A fast opening mode is assumed to function during the turbine generator load rejection, turbine trip, and feedwater controller failure transients as discussed in FSAR Sections 15.2.2, 15.2.3, and 15.1.2 (Refs. 2, 3, and 4). A pressure regulation mode is assumed to function during the control rod withdrawal error and recirculation flow controller failure transients as discussed in FSAR Sections 15.4.2 and 15.4.5 (Refs. 5 and 6). Both modes of operation are assumed to function for all bypass valves assumed in the applicable safety analyses. Opening the bypass valves during the above transients mitigates the increase in reactor vessel pressure, which affects both MCPR and LHGR during the event. An inoperable Main Turbine Bypass System may result in a MCPR and / or LHGR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of the NRC Policy Statement. (Ref. 7)

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System fast opening and pressure regulation modes are required to be OPERABLE to limit the pressure increase in the main steam lines and reactor pressure vessel during transients that cause a pressurization so that the Safety Limit MCPR and LHGR are not exceeded. With the Main Turbine Bypass System inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)") may be applied to allow this LCO to be met. The MCPR and LHGR limits for the inoperable Main Turbine Bypass System are specified in the COLR. An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. Licensing analyses credit an OPERABLE Main Turbine Bypass System as having both the bypass valve fast opening mode and pressure regulation mode. The fast opening mode is required for transients initiated by a turbine control valve or turbine stop valve closure. The pressure regulation mode is required for transients where the power increase exceeds the capability of the turbine control valves.

The cycle specific safety analyses assume a certain number of OPERABLE main turbine bypass valves as an input (i.e., one through five). Therefore, the Main Turbine Bypass System is considered OPERABLE when the number of OPERABLE bypass valves is greater than or equal to the number assumed in the safety analyses. The number of bypass valves assumed in the safety analyses is specified in the COLR. This response is within the assumptions of the applicable analysis (Refs. 2 – 6).

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 23% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during all applicable transients. As discussed in the Bases for LCOs 3.2.2 and 3.2.3, sufficient margin to these limits exists at < 23% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable and the MCPR and LHGR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met.

(continued)

BASES

ACTIONS

A.1 (continued)

Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the MCPR and LHGR limits accordingly. The 2-hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status or the MCPR and LHGR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 23% RTP. As discussed in the Applicability section, operation at < 23% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the applicable transients. The 4-hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

Cycling each required main turbine bypass valve through one complete cycle of full travel (including the fast opening feature) demonstrates that the valves are mechanically OPERABLE and will function when required. The 31-day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Operating experience has shown that these components usually pass the SR when performed at the 31 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.6.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals (simulate automatic actuation), the valves will actuate to their required position. The 24 month Frequency is based on the need to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.6.2 (continued)

perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is 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 unit specific documentation. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 7.7.1.5.
2. FSAR, Section 15.2.2.
3. FSAR, Section 15.2.3
4. FSAR, Section 15.1.2
5. FSAR, Section 15.4.2
6. FSAR, Section 15.4.5
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.7 PLANT SYSTEMS

B 3.7.8 Main Turbine Pressure Regulation System

BASES

BACKGROUND

The Main Turbine Pressure Regulation System is designed to control main steam pressure. The Main Turbine Pressure Regulation System contains two pressure regulators which are provided to maintain primary system pressure control. They independently sense pressure just upstream of the main turbine stop valves and compare it to two separate setpoints to create proportional error signals that produce each regulator's output. The outputs of both regulators feed into a high value gate. The regulator with the highest output controls the main turbine control valves. The lowest pressure setpoint gives the largest pressure error and thereby the largest regulator output. The backup regulator is nominally set 3 psi higher giving a slightly smaller error and a slightly smaller effective output of the controller. The main turbine pressure regulation function of the Turbine Electro Hydraulic Control System is discussed in the FSAR, Sections 7.7.1.5 (Ref. 1) and 15.2.1 (Ref. 2).

APPLICABLE SAFETY ANALYSES

A downscale failure of the primary or controlling pressure regulator as discussed in FSAR, Section 15.2.1 (Ref. 2) will cause the turbine control valves to begin to close momentarily. The pressure will increase, because the reactor is still generating the initial steam flow. The backup regulator will reposition the valves and re-establish steady-state operation above the initial pressure equal to the setpoint difference which is nominally 3 psi. Provided that the backup regulator takes control, the disturbance is mild, similar to a pressure setpoint change and no significant reduction in fuel thermal margins occur.

Failure of the backup pressure regulator is also discussed in FSAR, Section 15.2.1. If the backup pressure regulator fails downscale or is out of service when the primary regulator fails downscale, the turbine control valves (TCVs) will close in the servo or normal operating mode. Since the TCV closure is not a fast closure, there is no loss of EHC pressure to provide an anticipatory scram. The reactor pressure will increase to the point that a high neutron flux or a high reactor pressure scram is initiated to shut down the reactor. The increase in flux and pressure affects both MCPR and LHGR during the event. An inoperable Main Turbine Pressure Regulation System may result in a MCPR and/or LHGR penalty.

The Main Turbine Pressure Regulation System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Both Main Turbine Pressure Regulators are required to be OPERABLE to limit the pressure increase in the main steam lines and reactor pressure vessel during a postulated failure of the controlling pressure regulator so that the Safety Limit MCPR and LHGR are not exceeded. With one Main Turbine Pressure Regulator inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)") may be applied to allow this LCO to be met. The MCPR and LHGR limits for the inoperable Main Turbine Pressure Regulation System are specified in the COLR. An OPERABLE Main Turbine Pressure Regulation System requires that both Main Turbine Pressure Regulators be available so that if the controlling regulator fails downscale (i.e., in the direction of reduced control valve demand) a backup regulator is available to regain pressure control before fuel thermal margins can be significantly affected. An OPERABLE Main Turbine Pressure Regulation System causes the event where the controlling regulator fails downscale to be a non-limiting event from a thermal margin standpoint.

APPLICABILITY

The Main Turbine Pressure Regulation System is required to be OPERABLE at ≥ 23% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during all applicable transients. As discussed in the Bases for LCOs 3.2.2 and 3.2.3, sufficient margin to these limits exists at < 23% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If one Main Turbine Pressure Regulator is inoperable and the MCPR and LHGR limits for an inoperable Main Turbine Pressure Regulation System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Pressure Regulation System to OPERABLE status or adjust the MCPR and LHGR to be within the applicable limits accordingly. The 2-hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of a downscale failure of a Main Turbine Pressure Regulator.

(continued)

BASES

ACTIONS

B.1

If the Main Turbine Pressure Regulation System cannot be restored to OPERABLE status or the MCPR and LHGR limits for an inoperable Main Turbine Pressure Regulation System are not applied, THERMAL POWER must be reduced to < 23% RTP. As discussed in the Applicability section, operation at < 23% RTP results in sufficient margin to the required limits, and the Main Turbine Pressure Regulation System is not required to protect fuel integrity during the applicable transients.

The 4-hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

Verifying that both Main Turbine Pressure Regulators can be independently used to control pressure demonstrates that the Main Turbine Pressure Regulation System is OPERABLE and will function as required. The 92-day Frequency is based on engineering judgment, is consistent with the procedural controls governing pressure regulator operation, and ensures proper control of main turbine pressure. Operating experience has shown that these components usually pass the SR when performed at the 92-day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.2

The Main Turbine Pressure Regulators are designed so that a downscale failure of the controlling regulator will result in the backup regulator automatically assuming control. This SR demonstrates that, with the failure of the controlling pressure regulator, the backup pressure regulator will assume control. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage or unit start-up and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

(continued)

BASES

REFERENCES

1. FSAR, Section 7.7.1.5.

2. FSAR, Section 15.2.1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources-Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of two offsite power sources (preferred power sources, normal and alternate), and the onsite standby power sources (diesel generators (DGs) A, B, C and D). A fifth diesel generator, DG E, can be used as a substitute for any one of the four DGs A, B, C or D. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two preferred offsite power supplies and a single DG.

The two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System are supported by two independent offsite power sources. A 230 kV line from the Susquehanna T10 230 kV switching station feeds start-up transformer No. 10; and, a 230 kV tap from the 500-230 kV tie line feeds the startup transformer No. 20. The term "qualified circuits", as used within TS 3.8.1, is synonymous with the term "physically independent".

The two independent offsite power sources are supplied to and are shared by both units. These two electrically and physically separated circuits provide AC power, through startup transformers (ST) No. 10 and ST No. 20, to the four 4.16 kV Engineered Safeguards System (ESS) buses (A, B, C and D) for both Unit 1 and Unit 2. A detailed description of the offsite power network and circuits to the onsite Class 1E ESS buses is found in the FSAR, Section 8.2 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, automatic tap changers, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESS bus or buses.

(continued)

BASES

BACKGROUND (continued)

ST No. 10 and ST No. 20 each provide the normal source of power to two of the four 4.16 kV ESS buses in each Unit and the alternate source of power to the remaining two 4.16 kV ESS buses in each Unit. If any 4.16 kV ESS bus loses power, an automatic transfer from the normal to the alternate occurs after the normal supply breaker trips.

When off-site power is available to the 4.16 kV ESS Buses following a LOCA signal, the required ESS loads will be sequenced onto the 4.16 kV ESS Buses in order to compensate for voltage drops in the onsite power system when starting large ESS motors.

The onsite standby power source for 4.16 kV ESS buses A, B, C and D consists of five DGs. DGs A, B, C and D are dedicated to ESS buses A, B, C and D, respectively. DG E can be used as a substitute for any one of the four DGs (A, B, C or D) to supply the associated ESS bus. Each DG provides standby power to two 4.16 kV ESS buses—one associated with Unit 1 and one associated with Unit 2. The four "required" DGs are those aligned to a 4.16 kV ESS bus to provide onsite standby power for both Unit 1 and Unit 2.

A DG, when aligned to an ESS bus, starts automatically on a loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESS bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its respective bus after offsite power is tripped as a consequence of ESS bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to the ESS bus on a LOCA signal alone. Following the trip of offsite power, non-permanent loads are stripped from the 4.16 kV ESS Buses. When a DG is tied to the ESS Bus, loads are then sequentially connected to their respective ESS Bus by individual load timers. The individual load timers control the starting permissive signal to motor breakers to prevent overloading the associated DG.

In the event of loss of normal and alternate offsite power supplies, the 4.16 kV ESS buses will shed all loads except the 480 V load centers and the standby diesel generators will connect to the ESS busses. When a DG is tied to its respective ESS bus, loads are then sequentially connected to

(continued)

BASES

BACKGROUND (continued)

the ESS bus by individual load timers which control the permissive and starting signals to motor breakers to prevent overloading the DG.

In the event of a loss of normal and alternate offsite power supplies, the ESS electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading of the DGs in the process. Within 286 seconds after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service. Ratings for the DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3).

DGs A, B, C and D have the following ratings:

a. 4000 kW—continuous,
b. 4700 kW—2000 hours,

DG E has the following ratings:

a. 5000 kW—continuous,
b. 5500 kW—2000 hours.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 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 unit and supporting safe shutdown of the other unit. This includes maintaining the onsite or offsite AC sources

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

OPERABLE during accident conditions in the event of an assumed loss of all offsite power or all onsite AC power; and a worst case single failure.

AC sources satisfy Criterion 3 of the NRC Policy Statement (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System and four separate and independent DGs (A, B, C and D) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. DG E can be used as a substitute for any one of the four DGs A, B, C or D.

Qualified offsite circuits are those that are described in the FSAR, and are part of the licensing basis for the unit. In addition, the required automatic load timers for each ESF bus shall be OPERABLE.

The Safety Analysis for Unit 2 assumes the OPERABILITY of some equipment that receives power from Unit 1 AC Sources. Therefore, Unit 2 Technical Specifications establish requirements for the OPERABILITY of the DG(s) and qualified offsite circuits needed to support the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.7, Distribution Systems—Operating.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESS buses.

One OPERABLE offsite circuit exists when all of the following conditions are met:

1. An energized ST. No. 10 transformer with the load tap changer (LTC) in automatic operation.

2. The respective circuit path including energized ESS transformers 101 and 111 and feeder breakers capable of supplying three of the four 4.16kV ESS Buses.

(continued)

BASES

LCO
(continued)

3. Acceptable offsite grid voltage, defined as a voltage that is within the grid voltage requirements established for SSES. The grid voltage requirements include both a minimum grid voltage and an allowable grid voltage drop during normal operation, and for a predicted voltage for a trip of the unit.

   The Regional Transmission Operator (PJM), and/or the Transmission Power System Dispatcher, PPL EU, determine, monitor and report actual and/or contingency voltage (Predicted voltage) violations that occur for the SSES monitored offsite 230kV and 500kV buses.

   The offsite circuit is inoperable for any actual voltage violation, or a contingency voltage violation that occurs for a trip of a SSES unit, as reported by the transmission RTO or Transmission Power System Dispatcher.

   The offsite circuit is operable for any other predicted grid event (i.e., loss of the most critical transmission line or the largest supply) that does not result from the generator trip of a SSES unit. These conditions do not represent an impact on SSES operation that has been caused by a LOCA and subsequent generator trip. The design basis does not require entry into LCOs for predicted grid conditions that cannot result in a LOCA, delayed LOOP.

The other offsite circuit is Operable when all the following conditions are met:

1. An energized ST. No. 20 transformer with the load tap changer (LTC) in automatic operation.

2. The respective circuit path including energized ESS transformers 201 and 211 and feeder breakers capable of supplying three of the four 4.16kV ESS Buses.

3. Acceptable offsite grid voltage, defined as a voltage that is within the grid voltage requirements established for SSES. The grid voltage requirements include both a minimum grid voltage and an allowable grid voltage drop during normal operation, and for a predicted voltage for a trip of the unit.

(continued)

BASES

LCO
(continued)

The Regional Transmission Operator (PJM), and/or the Transmission Power System Dispatcher, PPL EU, determine, monitor and report actual and/or contingency voltage (Predicted voltage) violations that occur for the SSES monitored offsite 230kV and 500kV buses.

The offsite circuit is inoperable for any actual voltage violation, or a contingency voltage violation that occurs for a trip of a SSES unit, as reported by the transmission RTO or Transmission Power System Dispatcher.

The offsite circuit is operable for any other predicted grid event (i.e., loss of the most critical transmission line or the largest supply) that does not result from the generator trip of a SSES unit. These conditions do not represent an impact on SSES operation that has been caused by a LOCA and subsequent generator trip. The design basis does not require entry into LCOs for predicted grid conditions that cannot result in a LOCA, delayed LOOP.

Both offsite circuits are OPERABLE provided each meets the criteria described above and provided that no 4.16kV ESS Bus has less than one OPERABLE offsite circuit

(continued)

BASES

LCO (continued)

capable of supplying the required loads. If no OPERABLE offsite circuit is capable of supplying any of the 4.16 kV ESS Buses, one offsite source shall be declared inoperable. Unit 2 also requires Unit 1 offsite circuits to be OPERABLE.

If a Unit 1 4.16 kV bus is de-energized solely for the purpose of performing maintenance, it is not required to declare an offsite source or diesel generator inoperable.

Four of the five DGs are required to be Operable to satisfy the initial assumptions of the accident analyses. Each required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESS bus on detection of bus undervoltage after the normal and alternate supply breakers open. This sequence must be accomplished within 10 seconds. If a Unit 1 4.16 kV bus is isolated from its DG solely for the performance of bus maintenance, the DG is not required to be declared inoperable. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESS buses. These capabilities are required to be met from a variety of initial conditions, such as DG in standby with the engine hot and DG in normal standby conditions. Normal standby conditions for a DG mean that the diesel engine oil is being continuously circulated and engine coolant is circulated as necessary to maintain temperature consistent with manufacturer recommendations. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Although not normally aligned as a required DG, DG E is normally maintained OPERABLE (i.e., Surveillance Testing completed) so that it can be used as a substitute for any one of the four DGs A, B, C or D.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one ESS bus, with automatic transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to an ESS bus is required to

(continued)

BASES

LCO (continued)

have OPERABLE automatic transfer interlock mechanisms to each ESS bus to support OPERABILITY of that offsite circuit. If a Unit 1 – 4.16 kV bus is de-energized solely for the purpose of performing maintenance, automatic transfer interlock mechanisms for the de-energized bus are not required to be operable.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The ACTIONS are modified by a Note which allows entry into associated Conditions and Required Actions to be delayed for up to 8 hours when an OPERABLE diesel generator is placed in an inoperable status for the alignment of diesel generator E to or from the Class 1E distribution system. Use of this allowance requires both offsite circuits to be OPERABLE. Entry into the appropriate Conditions and Required Actions shall be made immediately upon the determination that substitution of a required diesel generator will not or can not be completed.

When Note 3 is in effect, the following restrictions (Reference 14) shall occur:

(continued)

BASES

ACTIONS (continued)

1.) No maintenance or testing that affects the reliability of the remaining OPERABLE Unit 1 and Unit 2 4160 V subsystems shall be scheduled. If any testing or maintenance activities must be performed during this time, an evaluation shall be performed in accordance with Title 10 to the *Code of Federal Regulations* (10 CFR) Section 50.65(a)(4).

2.) The required systems, subsystems, trains, components, and devices that depend on the remaining 4160 V buses shall be verified OPERABLE.

3.) The Unit 2 safety-related HPCI and RCIC pumps shall be controlled as "protected equipment" and not taken out of service for planned maintenance while a Unit 1 4160 V bus is out of service for extended maintenance.

Note 3 modifies the ACTIONS by allowing a Unit 1 4160 V subsystem (4.16 kV bus) to be de-energized for bus maintenance when Unit 1 is in Modes 4 or 5 and Unit 2 is in Modes 1, 2, or 3 without requiring either offsite circuit or the associated diesel generator to be declared inoperable. Only entry into LCO 3.8.7 Condition C is required for this maintenance activity. While in this configuration, immediate entry into LCO 3.8.1 is required for any offsite circuit or DG that becomes inoperable. Note 3 no longer applies.

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

(continued)

BASES

ACTIONS (continued)

A.2

Required Action A.2, which only applies if one 4.16 kV ESS bus cannot be powered from any offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features (e.g., system, subsystem, division, component, or device) are designed to be powered from redundant safety related 4.16 kV ESS buses. Redundant required features failures consist of inoperable features associated with an emergency bus redundant to the emergency bus that has no offsite power. The Completion Time for Required Action A.2 is intended to allow time for the operator to evaluate and repair any discovered inoperabilities. This Completion Time also allows an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. A 4.16 kV ESS bus has no offsite power supplying its loads; and

b. A redundant required feature on another 4.16 kV ESS bus is inoperable.

If, at any time during the existence of this Condition (one offsite circuit inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering no offsite power to one 4.16 kV ESS bus on the onsite Class 1E Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with any other emergency bus that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24

(continued)

BASES

ACTIONS

A.2 (continued)

hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A

(continued)

BASES

ACTIONS

A.3 (continued)

and B are entered concurrently. The "AND" connector between the 72 hours and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

B.1

To ensure a highly reliable power source remains with one required DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

(continued)

BASES

ACTIONS

B.2 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature powered from another diesel generator (Division 1 or 2) is inoperable.

If, at any time during the existence of this Condition (one required DG inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DGs results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.7 does not have to be performed. If the cause of inoperability exists on other DG(s), they are declared inoperable upon discovery, and Condition E of

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be determined not to exist on the remaining DG(s), performance of SR 3.8.1.7 suffices to provide assurance of continued OPERABILITY of those DGs. However, the second Completion Time for Required Action B.3.2 allows a performance of SR 3.8.1.7 completed up to 24 hours prior to entering Condition B to be accepted as demonstration that a DG is not inoperable due to a common cause failure.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 8), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition B for a period that should not exceed 72 hours. In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure of the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to

(continued)

BASES

ACTIONS

B.4 (continued)

complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

C.1

Required Action C.1 addresses actions to be taken in the event of concurrent inoperability of two offsite circuits. The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

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

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BASES

ACTIONS

C.1 (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 DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria. According to Regulatory Guide 1.93 (Ref. 7), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System Actions would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any ESS bus, Actions for LCO 3.8.7, "Distribution Systems-Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized bus.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition D for a period that should not exceed 12 hours. In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With two or more DGs inoperable and an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown. (The immediate shutdown could cause grid instability, which could result in a total loss of AC power.) Since any inadvertent unit 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.

According to Regulatory Guide 1.93 (Ref. 7), with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are

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BASES

ACTIONS

F.1 and F.2 (continued)

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

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11), as addressed in the FSAR.

The Safety Analysis for Unit 2 assumes the OPERABILITY of some equipment that receives power from Unit 1 AC Sources. Therefore, Surveillance requirements are established for the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required to support Unit 2 by LCO 3.8.7, Distribution Systems-Operating. As Noted at the beginning of the SRs, SR 3.8.1.1 through SR 3.8.1.20 are applicable to the Unit 2 AC sources and SR 3.8.1.21 is applicable to the Unit 1 AC sources.

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3793 V is the value assumed in the degraded voltage analysis and is approximately 90% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of

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BASES

SURVEILLANCE REQUIREMENTS (continued)

4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4400 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3). The lower Frequency Limit is necessary to support the LOCA analysis assumptions for low pressure ECCS pump flow rates. (Reference 12)

The Surveillance Table has been modified by a Note, to clarify the testing requirements associated with DG E. The Note is necessary to define the intent of the Surveillance Requirements associated with the integration of DG E. Specifically, the Note defines that a DG is only considered OPERABLE and required when it is aligned to the Class 1E distribution system. For example, if DG A does not meet the requirements of a specific SR, but DG E is substituted for DG A and aligned to the Class 1E distribution system, DG E is required to be OPERABLE to satisfy the LCO requirement of 4 DGs and DG A is not required to be OPERABLE because it is not aligned to the Class 1E distribution system. This is acceptable because only 4 DGs are assumed in the event analysis. Furthermore, the Note identifies when the Surveillance Requirements, as modified by SR Notes, have been met and performed, DG E can be substituted for any other DG and declared OPERABLE after performance of two SRs which verify switch alignment. This is acceptable because the testing regimen defined in the Surveillance Requirement Table ensures DG E is fully capable of performing all DG requirements.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

correct position to ensure that distribution buses and loads are connected to an Operable offsite power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2

Not Used.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the Cooper Bessemer Service Bulletin 728, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients do not invalidate the test.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

Note 5 provides the allowance that DG E, when not aligned as substitute for DG A, B, C and D but being maintained available, may use the test facility to satisfy loading requirements in lieu of synchronization with an ESS bus.

Note 6 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units, with the DG synchronized to the 4.16 kV ESS bus of Unit 1 for one periodic test and synchronized to the 4.16 kV ESS bus of Unit 2 during the next periodic test. This is acceptable because the purpose of the test is to demonstrate the ability of the DG to operate at its continuous rating (with the exception of DG E which is only required to be tested at the continuous rating of DGs A thru D) and this attribute is tested at the required Frequency. Each unit's circuit breakers and breaker control circuitry, which are only being tested every second test (due to the staggering of the tests), historically have a very low failure rate. If a DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit. In addition, if the test is scheduled to be performed on the other Unit, and the other Unit's TS allowance that provides an exception to performing the test is used (i.e., the Note to SR 3.8.2.1 for the other Unit provides an exception to performing this test when the other Unit is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment), or it is not possible to perform the test due to equipment availability, then the test shall be performed synchronized to this Unit's 4.16 kV ESS bus. The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR verifies the level of fuel oil in the engine mounted day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 55 minutes of DG A-D and 62 minutes of DG E operation at DG continuous rated load conditions.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the engine mounted day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 11). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. It is required to support 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 31 days because the design of the fuel transfer system requires that the transfer pumps operate automatically. Administrative controls ensure an adequate volume of fuel oil in the day tanks. This Frequency allows this aspect of DG Operability to be demonstrated during or following routine DG operation.

SR 3.8.1.7

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by Note 1 to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubicated to prevent undo wear and tear).

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

The DG starts from standby conditions and achieves the minimum required voltage and frequency within 10 seconds and maintains the required voltage and frequency when steady state conditions are reached. The ten second start requirement support the assumptions in the design bases LOCA analysis of FSAR Section 6.3 (Ref. 12)

To minimize testing of the DGs, Note 2 allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to one unit.

The time for the DG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation.

The 31 day Frequency is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of DG OPERABILITY.

SR 3.8.1.8

Transfer of each 4.16 kV ESS 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 24 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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of the automatic transfer of unit power supply could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

result, plant safety systems. The manual transfer of unit power supply should not result in any perturbation to the electrical distribution system, therefore, no mode restriction is specified. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in Unit 1 Technical Specifications tests the applicable logic associated with Unit 1. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 1. The NOTE only applies to Unit 2, thus the Unit 2 Surveillance shall not be performed with Unit 2 in MODE 1 or 2.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The largest single load for each a DG is a residual heat removal (RHR) pump (1425 kW). This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As recommended by Regulatory Guide 1.9 (Ref. 3), 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 DGs A, B, C, D and E, this represents 64.5 Hz, equivalent to 75% of the

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

difference between nominal speed and the overspeed trip setpoint.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 4.5 seconds specified is equal to 60% of the 7.5 second load sequence interval between loading of the RHR and core spray pumps during an undervoltage on the bus concurrent with a LOCA. The 6 seconds specified is equal to 80% of that load sequence interval. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c specify the steady state voltage and frequency values to which the system must recover following load rejection.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

To minimize testing of the DGs, a Note allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

To minimize testing of the DGs, a Note allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the ESS buses and respective 4.16 kV loads from the DG. It further demonstrates the capability of the DG to automatically achieve and maintain the required voltage and frequency within the specified time.

The DG auto-start time of 10 seconds is derived from requirements of the licensed accident analysis for responding to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. Note 1

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

allows all DG starts to be preceded by an engine prelube period (which for DG's A through D includes operation of he lube oil system to ensure the DGs turbo charger is sufficiently prelubricated). For the purpose of this testing, the DGs shall be started from standby conditions that is, with the engine oil being continuously circulated and engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with Unit 1. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODES 1, 2 or 3.

This SR is also modified by Note 3. The Note specifies when this SR is required to be performed for the DGs and the 4.16 kV ESS Buses. The Note is necessary because this SR involves an integrated test between the DGs and the 4.16 kV ESS Buses and the need for the testing regimen to include DG E being tested (substituted for all DGs for both units) with all 4.16 kV ESS Buses. To ensure the necessary testing is performed, the following rotational testing regimen has been established:

UNIT IN OUTAGE	DIESEL E SUBSTITUTED FOR
2	DG E not tested
1	Diesel Generator D
2	Diesel Generator A
1	DG E not tested
2	Diesel Generator B
1	Diesel Generator A
2	Diesel Generator C
1	Diesel Generator B
2	Diesel Generator D
1	Diesel Generator C

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The specified rotational testing regimen can be altered to facilitate unanticipated events which render the testing regimen impractical to implement, but any alternative testing regimen must provide an equivalent level of testing.

This SR does not have to be performed with the normally aligned DG when the associated 4.16 kV ESS bus is tested using DG E and DG E does not need to be tested when not substituted or aligned to the Class 1E distribution system. The allowances specified in the Note are acceptable because the tested attributes of each of the five DGs and each unit's four 4.16 kV ESS buses are verified at the specified Frequency (i.e., each DG and each 4.16 kV ESS bus is tested every 24 months). Specifically, when DG E is tested with a Unit 1 4.16 kV ESS bus, the attributes of the normally aligned DG, although not tested with the Unit 1 4.16 kV ESS bus, are tested with the Unit 2 4.16 kV ESS bus within the 24 month Frequency. The testing allowances do result in some circuit pathways which do not need to change state (i.e., cabling) not being tested on a 24 month Frequency. This is acceptable because these components are not required to change state to perform their safety function and when substituted--normal operation of DG E will ensure continuity of most of the cabling not tested.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a LOCA signal without loss of offsite power.

The requirement to verify the connection and power supply of permanent and auto connected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. SR 3.8.1.12.a through SR 3.8.1.12.d are performed with the DG running. SR 3.8.1.12.e can be performed when the DG is not running.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. Note 1 allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubricated). For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine oil being continuously circulated and engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

The reason for Note 2 is to allow DG E, when not aligned as substitute for DG A, B, C or D, to use the test facility to satisfy loading requirements in lieu of aligning with the Class 1E distribution system. When tested in this configuration, DG E satisfies the requirements of this test by completion of SR 3.8.1.12.a, b and c only. SR 3.8.1.12.d and 3.8.1.12.e may be performed by any DG aligned with the Class 1E distribution system or by any series of sequential,

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

overlapping, or total steps so that the entire connection and loading sequence is verified.

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on an ECCS initiation test signal. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by two Notes. To minimize testing of the DGs, Note 1 to SR 3.8.1.13 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

Note 2 provides the allowance that DG E, when not aligned as a substitute for DG A, B, C, and D but being maintained available, may use a simulated ECCS initiation signal.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), requires demonstration once per 24 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 90% to 100% of the continuous rating of the DG, and 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating of the DG. SSES has taken exception to this

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

requirement and performs the two hour run at the 2000 hour rating for each DG. The requirement to perform the two hour overload test can be performed in any order provided it is performed during a single continuous time period.

The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube discussed in SR 3.8.1.7, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

A 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 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance has been modified by four Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test.

To minimize testing of the DGs, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

Note 3 stipulates that DG E, when not aligned as substitute for DG A, B, C or D but being maintained available may use the test facility to satisfy the specified loading requirements in lieu of synchronization with an ESS bus.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from full load temperatures and achieve the required voltage

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

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 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test.

Note 2 allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbocharger is sufficiently prelubricated) to minimize wear and tear on the diesel during testing.

To minimize testing of the DGs, Note 3 allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

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 DG controls are in isochronous and the output breaker is open.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a note to accommodate the testing regimen necessary for DG E. See SR 3.8.1.11 for the Bases of the Note.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage, the DG controls in isochronous, and the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 10), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirements associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This test is performed by verifying that after the DG is tripped, the offsite source originally in parallel with the DG, remains connected to the affected 4.16 kV ESS Bus. SR 3.8.1.12 is performed separately to verify the proper offsite loading sequence.

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a note to accommodate the testing regimen necessary for DG E. See SR 3.8.1.11 for the Bases of the Note.

Under accident conditions, loads are sequentially connected to the bus by individual load timers which control the permissive and starting signals to motor breakers to prevent overloading of the AC Sources due to high motor starting currents. The load sequence time interval tolerance ensures that sufficient time exists for the AC Source to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESS buses. A list of the required timers and the associated setpoints are included in the Bases as Table B 3.8.1-1, Unit 1 and Unit 2 Load Timers. Failure of a timer identified as an offsite power timer may result in both offsite sources inoperable. Failure of any other timer may result in the associated DG being inoperable. A timer is considered failed for this SR if it will not ensure that the associated load will energize within the Allowable Value specified in Table B 3.8.1-1. These conditions will require entry into applicable Condition of this specification. With a load timer inoperable, the load can be rendered inoperable to restore OPERABILITY to the associated AC sources. In this condition, the Conditions and Required Actions of the associated specification shall be entered for the equipment rendered inoperable.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.18

This SR is modified by a Note that specifies that load timers associated with equipment that has automatic initiation

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

capability disabled are not required to be Operable. This is acceptable because if the load does not start automatically, the adverse effects of an improper loading sequence are eliminated. Furthermore, load timers are associated with individual timers such that a single timer only affects a single load.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. To simulate the non-LOCA unit 4.16 kV ESS Bus loads on the DG, bounding loads are energized on the tested 4.16 kV ESS Bus after all auto connected emergency loads are energized.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. Note 1 allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubricated). For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine oil being continuously circulated and

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

Note 2 is necessary to accommodate the testing regimen associated with DG E. See SR 3.8.1.11 for the Bases of the Note.

The reason for Note 3 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with Unit 1. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2 or 3 does not have applicability to Unit 1. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODE 1, 2 or 3.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously. The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. The Note allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubricated.) For the purpose of this testing, the DG's must be started from standby conditions, that is, with the engine oil continuously circulated and engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

Note 2 is necessary to identify that this test does not have to be performed with DG E substituted for any DG. The allowance is acceptable based on the design of the DG E transfer switches. The transfer of control, protection, indication, and alarms is by switches at two separate locations. These switches provide a double break between DG E and the redundant system within the transfer switch panel. The transfer of power is through circuit breakers at two separate locations for each redundant system. There are four normally empty switchgear positions at DG E facility, associated with each of the four existing DGs. Only one circuit breaker is available at this location to be inserted into one of the four positions. At each of the existing DGs, there are two switchgear positions with only one circuit breaker available. This design provides two open circuits between redundant power sources. Therefore, based on the described design, it can be concluded that DG redundancy and independence is maintained regardless of whether DG E is substituted for any other DG.

SR 3.8.1.21

This Surveillance is provided to direct that the appropriate Surveillances for Unit 1 AC sources required to support Unit 2 are governed by the Unit 2 Technical Specifications. With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.1.1 through SR 3.8.1.20) are applicable to the Unit 2 AC sources only. Meeting the SR requirements of Unit 1 LCO 3.8.1 will satisfy all Unit 2 requirements for Unit 1 AC sources. However, six Unit 1 LCO 3.8.1 SRs, if not required to support Unit 1 OPERABILITY requirements, are not required when demonstrating Unit 1 sources are capable of supporting Unit 2. SR 3.8.1.8 is not required if only one Unit 1 offsite circuit is required by the Unit 2 Specification.
SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, and SR 3.8.1.19 are not required since these SRs test the Unit 2 ECCS initiation signal, which is not needed for the AC sources to be OPERABLE on Unit 2.
SR 3.8.1.20 is not required since starting independence is not required with the DG(s) not required to be OPERABLE.

The Frequency required by the applicable Unit 1 SR also governs performance of that SR for Unit 2.

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SR 3.8.1.20 (continued)

As Noted, if Unit 1 is in MODE 4 or 5, the Note to Unit 1 SR 3.8.2.1 is applicable. This ensures that a Unit 2 SR will not require a Unit 1 SR to be performed, when the Unit 1 Technical Specifications do not require performance of a Unit 1 SR. (However, as stated in the Unit 2 SR 3.8.2.1 Note, while performance of an SR is not required, the SR still must be met).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Section 8.2.
3. Regulatory Guide 1.9.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
7. Regulatory Guide 1.93.
8. Generic Letter 84-15.
9. 10 CFR 50, Appendix A, GDC 18.
10. IEEE Standard 308.
11. Regulatory Guide 1.137.
12. FSAR, Section 6.3.
13. ASME Boiler and Pressure Vessel Code, Section XI.
14. Letter from R. V. Guzman (USNRC) to B. T. McKinney (PPL) "Susquehanna Steam Electric Station, Unit 2 – Issuance of Amendment Re : Electrical Power Systems Technical Specification 3.8.1 (T.A.C. MD4766)", dated February 19, 2008.

TABLE B 3.8.1-1 (page 1 of 2)
UNIT 1 AND UNIT 2 LOAD TIMERS

DEVICE TAG NO.	SYSTEM LOADING TIMER	LOCATION	NOMINAL SETTING (seconds)	ALLOWABLE VALUE (seconds)
62A-20102	RHR Pump 1A	1A201	3	≥ 2.7 and ≤ 3.6
62A-20202	RHR Pump 1B	1A202	3	≥ 2.7 and ≤ 3.6
62A-20302	RHR Pump 1C	1A203	3	≥ 2.7 and ≤ 3.6
62A-20402	RHR Pump 1D	1A204	3	≥ 2.7 and ≤ 3.6
62A-20102	RHR Pump 2A	2A201	3	≥ 2.7 and ≤ 3.6
62A-20202	RHR Pump 2B	2A202	3	≥ 2.7 and ≤ 3.6
62A-20302	RHR Pump 2C	2A203	3	≥ 2.7 and ≤ 3.6
62A-20402	RHR Pump 2D	2A204	3	≥ 2.7 and ≤ 3.6
E11A-K202B	RHR Pump 1C (Offsite Power Timer)	1C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K120A	RHR Pump 1C (Offsite Power Timer)	1C617	7.0	≥ 6.5 and ≤ 7.5
E11A-K120B	RHR Pump 1D (Offsite Power Timer)	1C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K202A	RHR Pump 1D (Offsite Power Timer)	1C617	7.0	≥ 6.5 and ≤ 7.5
E11A-K120A	RHR Pump 2C (Offsite Power Timer)	2C617	7.0	≥ 6.5 and ≤ 7.5
E11A-K202B	RHR Pump 2C (Offsite Power Timer)	2C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K120B	RHR Pump 2D (Offsite Power Timer)	2C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K202A	RHR Pump 2D (Offsite Power Timer)	2C617	7.0	≥ 6.5 and ≤ 7.5
E21A-K116A	CS Pump 1A	1C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K116B	CS Pump 1B	1C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K125A	CS Pump 1C	1C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K125B	CS Pump 1D	1C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K116A	CS Pump 2A	2C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K116B	CS Pump 2B	2C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K125A	CS Pump 2C	2C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K125B	CS Pump 2D	2C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K16A	CS Pump 1A (Offsite Power Timer)	1C626	15	≥ 14.0 and ≤ 16.0
E21A-K16B	CS Pump 1B (Offsite Power Timer)	1C627	15	≥ 14.0 and ≤ 16.0
E21A-K25A	CS Pump 1C (Offsite Power Timer)	1C626	15	≥ 14.0 and ≤ 16.0
E21A-K25B	CS Pump 1D (Offsite Power Timer)	1C627	15	≥ 14.0 and ≤ 16.0
E21A-K16A	CS Pump 2A (Offsite Power Timer)	2C626	15	≥ 14.0 and ≤ 16.0
E21A-K16B	CS Pump 2B (Offsite Power Timer)	2C627	15	≥ 14.0 and ≤ 16.0
E21A-K25A	CS Pump 2C (Offsite Power Timer)	2C626	15	≥ 14.0 and ≤ 16.0
E21A-K25B	CS Pump 2D (Offsite Power Timer)	2C627	15	≥ 14.0 and ≤ 16.0
62AX2-20108	Emergency Service Water	1A201	40	≥ 36 and ≤ 44
62AX2-20208	Emergency Service Water	1A202	40	≥ 36 and ≤ 44
62AX2-20303	Emergency Service Water	1A203	44	≥ 39.6 and ≤ 48.4
62AX2-20403	Emergency Service Water	1A204	48	≥ 43.2 and ≤ 52.8
62X3-20404	Control Structure Chilled Water System	OC877B	60	≥ 54
62X3-20304	Control Structure Chilled Water System	OC877A	60	≥ 54
62X-20104	Emergency Switchgear Rm Cooler A & RHR SW Pump H&V Fan A	OC877A	60	≥ 54
62X-20204	Emergency Switchgear Rm Cooler B & RHR SW Pump H&V Fan B	OC877B	60	≥ 54
62X-5653A	DG Room Exhaust Fan E3	OB565	60	≥ 54
62X-5652A	DG Room Exhausts Fan E4	OB565	60	≥ 54
262X-20204	Emergency Switchgear Rm Cooler B	OC877B	120	≥ 54
262X-20104	Emergency Switchgear Rm Cooler A	OC877A	120	≥ 54
62X-546	DG Rm Exh Fan D	OB546	120	≥ 54

(continued)

TABLE B 3.8.1-1 (page 2 of 2)
UNIT 1 AND UNIT 2 LOAD TIMERS

DEVICE TAG NO.	SYSTEM LOADING TIMER	LOCATION	NOMINAL SETTING (seconds)	ALLOWABLE VALUE (seconds)
62X-536	DG Rm Exh Fan C	OB536	120	≥ 54
62X-526	DG Rm Exh Fan B	OB526	120	≥ 54
62X-516	DG Rm Exh Fan A	OB516	120	≥ 54
CRX-5652A	DG Room Supply Fans E1 and E2	OB565	120	≥ 54
62X2-20410	Control Structure Chilled Water System	OC876B	180	≥ 54
62X1-20304	Control Structure Chilled Water System	OC877A	180	≥ 54
62X2-20310	Control Structure Chilled Water System	OC876A	180	≥ 54
62X1-20404	Control Structure Chilled Water System	OC877B	180	≥ 54
62X2-20304	Control Structure Chilled Water System	OC877A	210	≥ 54
62X2-20404	Control Structure Chilled Water System	OC877B	210	≥ 54
62X-K11BB	Emergency Switchgear Rm Cooling Compressor B	2CB250B	260	≥ 54
62X-K11AB	Emergency Switchgear Rm Cooling Compressor A	2CB250A	260	≥ 54

B 3.3 INSTRUMENTATION

B 3.3.1.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor scram when one or more monitored parameters exceed their specified limits, to preserve the integrity of the fuel cladding and the Reactor Coolant System (RCS) and minimize the energy that must be absorbed following a loss of coolant accident (LOCA). This can be accomplished either automatically or manually.

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters and equipment performance. The LSSS are defined in this Specification as the Allowable Values, which, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits, including Safety Limits (SLs) during Design Basis Accidents (DBAs).

The RPS, as shown in the FSAR, Figure 7.2-1 (Ref. 1), includes sensors, relays, bypass circuits, and switches that are necessary to cause initiation of a reactor scram. Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the scram logic are from instrumentation that monitors reactor vessel water level, reactor vessel pressure, neutron flux, main steam line isolation valve position, turbine control valve (TCV) fast closure trip oil pressure, turbine stop valve (TSV) position, drywell pressure, and scram discharge volume (SDV) water level, as well as reactor mode switch in shutdown position and manual scram signals. There are at least four redundant sensor input signals from each of these parameters (with the exception of the reactor mode switch in shutdown scram signal). When the setpoint is reached, the channel sensor actuates, which then outputs an RPS trip signal to the trip logic. Table B 3.3.1.1-1 summarizes the diversity of sensors capable of initiating scrams during anticipated operating transients typically analyzed.

The RPS is comprised of two independent trip systems (A and B) with two logic channels in each trip system (logic

(continued)

BASES

BACKGROUND (continued)

channels A1 and A2, B1 and B2) as shown in Reference 1. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so that either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as a one-out-of-two taken twice logic. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed.

Two AC powered scram pilot solenoids are located in the hydraulic control unit for each control rod drive (CRD). Each scram pilot valve is operated with the solenoids normally energized. The scram pilot valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either scram pilot valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both scram pilot valve solenoids must be de-energized to cause a control rod to scram. The scram valves control the supply and discharge paths for the CRD water during a scram. One of the scram pilot valve solenoids for each CRD is controlled by trip system A, and the other solenoid is controlled by trip system B. Any trip of trip system A in conjunction with any trip in trip system B results in de-energizing both solenoids, air bleeding off, scram valves opening, and control rod scram.

The DC powered backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS. Additionally, the RPS System controls the SDV vent and drain valves such that when both trip systems trip, the SDV vent and drain valves close to isolate the SDV.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 3, 4, 5 and 6. The RPS initiates a reactor scram before the monitored parameter values reach the Allowable Values, specified by the setpoint methodology and listed in Table 3.3.1.1-1 to preserve the integrity of the fuel cladding, the reactor coolant pressure boundary (RCPB), and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the containment by minimizing the energy that must be absorbed following a LOCA.

RPS instrumentation satisfies Criterion 3 of the NRC Policy Statement. (Ref. 2)

Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The OPERABILITY of the RPS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.1.1-1. Each Function must have a required number of OPERABLE channels per RPS trip system, with their setpoints within the specified Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time.

Allowable Values are specified for each RPS Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter reaches the setpoint, the associated device changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The OPERABILITY of scram pilot valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this LCO.

The individual Functions are required to be OPERABLE in the MODES specified in the table, which may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions are required in each MODE to provide primary and diverse initiation signals.

The RPS is required to be OPERABLE in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and, therefore, are not required to have the capability to scram. Provided all other control rods remain inserted, the RPS function is not required. In this condition, the required SDM (LCO 3.1.1) and refuel position one-rod-out interlock (LCO 3.9.2) ensure that no event requiring RPS will occur. During normal operation in MODES 3 and 4, all control rods are fully inserted and the Reactor Mode Switch Shutdown Position control rod withdrawal block (LCO 3.3.2.1) does not allow any control rod to be withdrawn. Under these conditions, the RPS function is not required to be OPERABLE. The exception to this is Special Operations (LCO 3.10.3 and LCO 3.10.4) which ensure compliance with appropriate requirements.

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

Intermediate Range Monitor (IRM)

1.a. Intermediate Range Monitor Neutron Flux-High

The IRMs monitor neutron flux levels from the upper range of the source range monitor (SRM) to the lower range of the average power range monitors (APRMs). The IRMs are capable of generating trip signals that can be used to prevent fuel

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Intermediate Range Monitor Neutron Flux-High (continued)

damage resulting from abnormal operating transients in the intermediate power range. In this power range, the most significant source of reactivity change is due to control rod withdrawal. The IRM provides
diverse protection for the rod worth minimizer (RWM), which monitors and controls the movement of control rods at low power. The RWM prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 5). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, generic analyses have been performed (Ref. 3) to evaluate the consequences of control rod withdrawal events during startup that are mitigated only by the IRM. This analysis, which assumes that one IRM channel in each trip system is bypassed, demonstrates that the IRMs provide protection against local control rod withdrawal errors and results in peak fuel energy depositions below the 170 cal/gm fuel failure threshold criterion.

The IRMs are also capable of limiting other reactivity excursions during startup, such as cold water injection events, although no credit is specifically assumed.

The IRM System is divided into two trip systems, with four IRM channels inputting to each trip system. The analysis of Reference 3 assumes that one channel in each trip system is bypassed. Therefore, six channels with three channels in each trip system are required for IRM OPERABILITY to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The analysis of Reference 3 has adequate conservatism to permit an IRM Allowable Value of 122 divisions of a 125 division scale.

The Intermediate Range Monitor Neutron Flux—High Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Intermediate Range Monitor Neutron Flux-High (continued)

MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the APRM System and the RWM provide protection against control rod withdrawal error events and the IRMs are not required. In addition, the Function is automatically bypassed when the Reactor Mode Switch is in the Run position.

1.b. Intermediate Range Monitor-Inop

This trip signal provides assurance that a minimum number of IRMs are OPERABLE. Anytime an IRM mode switch is moved to any position other than "Operate," the detector voltage drops below a preset level, or when a module is not plugged in, an inoperative trip signal will be received by the RPS unless the IRM is bypassed. Since only one IRM in each trip system may be bypassed, only one IRM in each RPS trip system may be inoperable without resulting in an RPS trip signal.

This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

Six channels of Intermediate Range Monitor—Inop with three channels in each trip system are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

Since this Function is not assumed in the safety analysis, there is no Allowable Value for this Function.

This Function is required to be OPERABLE when the Intermediate Range Monitor Neutron Flux—High Function is required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Average Power Range Monitor (APRM)

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. Each APRM channel also includes an Oscillation Power Range Monitor (OPRM) Upscale Function, which monitors small groups of LPRM signals to detect thermal-hydraulic instabilities.

The APRM trip System is divided into four APRM channels and four 2-out-of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed. A trip from any one unbypassed APRM will result in a "half-trip" in all four of the voter channels, but no trip inputs to either RPS trip system.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Trip Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels, which in turn results in two trip inputs into each RPS trip system logic channel (A1, A2, B1, and B2), thus resulting in a full scram signal. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. In addition, to provide adequate coverage of the entire core consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located must be OPERABLE for each APRM channel, with no more than 9, LPRM detectors declared inoperable since the most recent APRM gain calibration. Per Reference 23, the minimum input

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Average Power Range Monitor (APRM) (continued)

requirement for an APRM channel with 43 LPRM inputs is determined given that the total number of LPRM outputs used as inputs to an APRM channel that may be bypassed shall not exceed twenty-three (23). Hence, 20 LPRM inputs producing a channel trip signal. needed to be operable. For the OPRM Trip Function 2.f, each LPRM in an APRM channel is further associated in a pattern of OPRM "cells," as described in References 17 and 18. Each OPRM cell is capable of producing a channel trip signal.

2.a. Average Power Range Monitor Neutron Flux-High (Setdown)

For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux-High (Setdown) Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux-High (Setdown) Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux-High Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux-High (Setdown) Function will provide the primary trip signal for a corewide increase in power.

The Average Power Range Monitor Neutron Flux-High (Setdown) Function together with the IRM-High Function provide mitigation for the control rod withdrawal event during startup (Section 15.4.1 of Ref 5). Also, the Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 23% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 23% RTP.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 23% RTP.

The Average Power Range Monitor Neutron Flux-High (Setdown) Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists. In MODE 1, the Average Power Range Monitor Neutron Flux-High Function provides protection against reactivity transients and the RWM protects against control rod withdrawal error events.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux-High (Setdown) (continued)

There are provisions in the design of the NUMAC PRNM that given certain circumstances, such as loss of one division of RPS power, an individual APRM will default to a "run" mode condition logic. If the plant is in mode 2 when this occurs, the individual APRM will be in a condition where the 'run' mode setpoint (Function 2.c) and not the 'setdown' setpoint (Function 2.a) will be applied. If this condition occurs while in reactor mode 2 condition, the appropriate LCO condition per Table 3.3.1.1-1 needs to be entered.

2.b. Average Power Range Monitor Simulated Thermal Power-High

The Average Power Range Monitor Simulated Thermal Power-High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Neutron Flux-High Function Allowable Value. The Average Power Range Monitor Simulated Thermal Power-High Function is not credited in any plant Safety Analyses. The Average Power Range Monitor Simulated Thermal Power–High Function Limit is set above the APRM Rod Block to provide defense in depth to the APRM Neutron Flux–High for transients where THERMAL POWER increases slowly (such as loss of feedwater heating event). During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Neutron Flux-High Function will provide a scram signal before the Average Power Range Monitor Simulated Thermal Power-High Function setpoint is exceeded.

The Average Power Range Monitor Simulated Thermal Power–High Function uses a trip level generated based on recirculation loop drive flow (W) representative of total core flow. Each APRM channel uses one total recirculation drive flow signal. The total recirculation drive

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Simulated Thermal Power-High (continued)

flow signal is generated by the flow processing logic, part of the APRM channel, by summing the flow calculated from two flow transmitter signal inputs, one from each of the two recirculation drive flow loops. The flow processing logic OPERABILITY is part of the APRM channel OPERABILITY requirements for this Function.

The adequacy of drive flow as a representation of core flow is ensured through drive flow alignment, accomplished by SR 3.3.1.1.20.

A note is included, applicable when the plant is in single recirculation loop operation per LCO 3.4.1, which requires reducing by ΔW the recirculation flow value used in the APRM Simulated Thermal Power–High Allowable Value equation. The Average Power Range Monitor Scram Function varies as a function of recirculation loop drive flow (W). ΔW is defined as the difference in indicated drive flow (in percent of drive flow, which produces rated core flow) between two-loop and single-loop operation at the same core flow. The value of ΔW is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. This adjusted Allowable Value thus maintains thermal margins essentially unchanged from those for two-loop operation.

The THERMAL POWER time constant of < 7 seconds is based on the fuel heat transfer dynamics and provides a signal proportional to the THERMAL POWER. The simulated thermal time constant is part of filtering logic in the APRM that simulates the relationship between neutron flux and core thermal power.

The Average Power Range Monitor Simulated Thermal Power-High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

2.c. Average Power Range Monitor Neutron Flux-High

The Average Power Range Monitor Neutron Flux-High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 4, the Average Power Range Monitor Neutron Flux-High

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Average Power Range Monitor Neutron Flux-High (continued)

Function is assumed to terminate the main steam isolation valve (MSIV)
closure event and, along with the safety/relief valves (S/RVs), limit the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 5) takes credit for the Average Power Range Monitor Neutron Flux-High Function to terminate the CRDA.

The CRDA analysis assumes that reactor scram occurs on Average Power Range Monitor Neutron Flux-High Function.

The Average Power Range Monitor Neutron Flux-High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Neutron Flux-High Function is assumed in the CRDA analysis, which is applicable in MODE 2, the Average Power Range Monitor Neutron Flux-High (Setdown) Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Range Monitor Neutron Flux-High Function is not required in MODE 2.

2.d. Average Power Range Monitor-Inop

Three of the four APRM channels are required to be OPERABLE for each of the APRM Functions. This Function (Inop) provides assurance that the minimum number of APRM channels are OPERABLE.

For any APRM channel, any time its mode switch is not in the "Operate" position, an APRM module required to issue a trip is unplugged, or the automatic self-test system detects a critical fault with the APRM channel, an Inop trip is sent to all four voter channels. Inop trips from two or more unbypassed APRM channels result in a trip output from each of the four voter channels to its associated trip system.

This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Average Power Range Monitor-Inop (continued)

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

2.e. 2-out-of-4 Voter

The 2-out-of-4 Voter Function provides the interface between the APRM Functions, including the OPRM Trip Function, and the final RPS trip system logic. As such, it is required to be OPERABLE in the MODES where the APRM Functions are required and is necessary to support the safety analysis applicable to each of those Functions. Therefore, the 2-out-of-4 Voter Function is required to be OPERABLE in MODES 1 and 2.

All four voter channels are required to be OPERABLE. Each voter channel includes self-diagnostic functions. If any voter channel detects a critical fault in its own processing, a trip is issued from that voter channel to the associated RPS trip system.

The Two-Out-Of-Four Logic Module includes both the 2-out-of-4 Voter hardware and the APRM Interface hardware. The 2-out-of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-out-of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 15 took credit for this redundancy in the justification of the 12-hour Completion Time for Condition A, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

There is no Allowable Value for this Function.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.f. Oscillation Power Range Monitor (OPRM) Trip

The OPRM Trip Function provides compliance with GDC 10, "Reactor Design," and GDC 12, "Suppression of Reactor Power Oscillations" thereby providing protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

References 17, 18 and 19 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (confirmation count and cell amplitude), the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Trip Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Trip Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

The OPRM Trip Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the MCPR SL is exceeded. Three of the four channels are required to be OPERABLE.

The OPRM Trip is automatically enabled (bypass removed) when THERMAL POWER is ≥ 25% RTP, as indicated by the APRM Simulated Thermal Power, and reactor core flow is ≤ the value defined in the COLR, as indicated by APRM measured recirculation drive flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations are expected to occur. Reference 21 includes additional discussion of OPRM Trip enable region limits.

These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region once the region is entered.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.f. Oscillation Power Range Monitor (OPRM) Trip (continued)

The OPRM Trip Function is required to be OPERABLE when the plant is at ≥ 23% RTP. The 23% RTP level is selected to provide margin in the unlikely event that a reactor power increase transient occurring without operator action while the plant is operating below 25% RTP causes a power increase to or beyond the 25% APRM Simulated Thermal Power OPRM Trip auto-enable setpoint. This OPERABILITY requirement assures that the OPRM Trip auto-enable function will be OPERABLE when required.

An APRM channel is also required to have a minimum number of OPRM cells OPERABLE for the Upscale Function 2.f to be OPERABLE. The OPRM cell operability requirements are documented in the Technical Requirements Manual, TRO 3.3.9, and are established as necessary to support the trip setpoint calculations performed in accordance with methodologies in Reference 19.

An OPRM Trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel OPRM Trip from that channel. An OPRM Trip is also issued from the channel if either the growth rate or amplitude-based algorithms detect oscillatory changes in the neutron flux for one or more cells in that channel. (Note: To facilitate placing the OPRM Trip Function 2.f in one APRM channel in a "tripped" state, if necessary to satisfy a Required Action, the APRM equipment is conservatively designed to force an OPRM Trip output from the APRM channel if an APRM Inop condition occurs, such as when the APRM chassis keylock switch is placed in the Inop position.)

There are three "sets" of OPRM related setpoints or adjustment parameters: a) OPRM Trip auto-enable region setpoints for STP and drive flow; b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; and c) period based detection algorithm tuning parameters.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.f. Oscillation Power Range Monitor (OPRM) Trip (continued)

The first set, the OPRM Trip auto-enable setpoints, as discussed in the SR 3.3.1.1.19 Bases, are treated as nominal setpoints with no additional margins added. The settings are defined in the Technical Requirements Manual, TRO 3.3.9, and confirmed by SR 3.3.1.1.19. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 19, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by requirements in the Technical Requirements Manual, TRO 3.3.9.

3. Reactor Vessel Steam Dome Pressure-High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor
coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. This trip Function is assumed in the low power generator load rejection without bypass and the recirculation flow controller failure (increasing) event. However, the Reactor Vessel Steam Dome Pressure-High Function initiates a scram for transients that results in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 4, reactor scram (the analyses conservatively assume a scram from either the Average Power Range Monitor Neutron Flux-High signal, or the Reactor Vessel Steam Dome Pressure-High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure instruments that sense reactor pressure. The Reactor Vessel Steam Dome Pressure-High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure-High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the RCS is pressurized and the potential for pressure increase exists.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Reactor Vessel Water Level-Low, Level 3

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level-Low, Level 3 Function is assumed in the analysis of the recirculation line break (Ref. 6). The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level-Low, Level 3 signals are initiated from four level instruments that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Water Level—Low, Level 3 Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

The Reactor Vessel Water Level—Low, Level 3 Allowable Value is selected to ensure that during normal operation the separator skirts are not uncovered (this protects available recirculation pump net positive suction head (NPSH) from significant carryunder) and, for transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS subsystems at Reactor Vessel Water—Low Low Low, Level 1 will not be required.

The Function is required in MODES 1 and 2 where considerable energy exists in the RCS resulting in the limiting transients and accidents. ECCS initiations at Reactor Vessel Water Level—Low Low, Level 2 and Low Low Low,

Level 1 provide sufficient protection for level transients in all other MODES.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Main Steam Isolation Valve-Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the nuclear steam supply system and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve-Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analysis of Reference 4, the Average Power Range Monitor Neutron Flux-High Function, along with the S/RVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis.

Additionally, MSIV closure is assumed in the transients analyzed in Reference 5 (e.g., low steam line pressure, manual closure of MSIVs, high steam line flow). The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

MSIV closure signals are initiated from position switches located on each of the eight MSIVs. Each MSIV has two position switches; one inputs to RPS trip system A while the other inputs to RPS trip system B. Thus, each RPS trip system receives an input from eight Main Steam Isolation Valve—Closure channels, each consisting of one position switch. The logic for the Main Steam Isolation Valve—Closure Function is arranged such that either the inboard or outboard valve on three or more of the main steam lines must close in order for a scram to occur.

The Main Steam Isolation Valve-Closure Allowable Value is specified to ensure that a scram occurs prior to a significant reduction in steam flow, thereby reducing the severity of the subsequent pressure transient.

Sixteen channels (arranged in pairs) of the Main Steam Isolation Valve-Closure Function, with eight channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude the scram from this Function on a valid signal. This Function is only required in MODE 1 since, with the MSIVs open and the heat generation rate high, a pressurization transient can occur if the MSIVs close. In addition, the Function is automatically bypassed when the Reactor Mode Switch is not in the Run position. In MODE 2, the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Drywell Pressure-High

High pressure in the drywell could indicate a break in the RCPB. A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and the drywell. The Drywell Pressure—High Function is assumed in the analysis of the recirculation line break (Ref. 6). The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

High drywell pressure signals are initiated from four pressure instruments that sense drywell pressure. The Allowable Value was selected to be as low as possible and indicative of a LOCA inside primary containment.

Four channels of Drywell Pressure-High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODES 1 and 2 where considerable energy exists in the RCS, resulting in the limiting transients and accidents.

7.a, 7.b. Scram Discharge Volume Water Level – High

The SDV receives the water displaced by the motion of the CRD pistons during a reactor scram. Should this volume fill to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. Therefore, a reactor scram is initiated while the remaining free volume is still sufficient to accommodate the water from a full core scram. The two types of Scram Discharge Volume Water Level—High Functions are an input to the RPS logic. No credit is taken for a scram initiated from these Functions for any of the design basis accidents or transients analyzed in the FSAR. However, they are retained to ensure the scram function remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs is measured by two float type level switches and two level transmitters with trip units for a total of eight level signals. The outputs of these devices are arranged so that there is a signal from a level switch and a level transmitter with trip unit to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference 8.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7.a, 7.b. Scram Discharge Volume Water Level – High (continued)

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram.

Four channels of each type of Scram Discharge Volume Water Level-High Function, with two channels of each type in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Stop Valve-Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve-Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 5. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded. Turbine Stop Valve—Closure signals are initiated from position switches located on each of the four TSVs. Two independent position switches are associated with each stop valve. One of the two switches provides input to RPS trip system A; the other, to RPS trip system B.

Thus, each RPS trip system receives an input from four Turbine Stop Valve-Closure channels, each consisting of one position switch. The logic for the Turbine Stop Valve-Closure Function is such that three or more TSVs must be closed to produce a scram. This Function must be enabled at THERMAL POWER ≥ 26% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function non-conservatively, THERMAL POWER is derived from first stage pressure. The main turbine bypass valves must not cause the trip Function to be bypassed when THERMAL POWER is ≥ 26% RTP.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Turbine Stop Valve-Closure (continued)

The Turbine Stop Valve—Closure Allowable Value is selected to be high enough to detect imminent TSV closure, thereby reducing the severity of the subsequent pressure transient.

Eight channels (arranged in pairs) of Turbine Stop Valve-Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if any three TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ 26% RTP. This Function is not required when THERMAL POWER is < 26% RTP since the Reactor Vessel Steam Dome Pressure- High and the Average Power Range Monitor Neutron Flux-High Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 5. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure-Low signals are initiated by the electrohydraulic control (EHC) fluid pressure at each control valve. One pressure instrument is associated with each control valve, and the signal from each transmitter is assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 26% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function non-conservatively, THERMAL POWER is derived from first stage pressure. The main turbine bypass valves must not cause the trip Function to be bypassed when THERMAL POWER is ≥ 26% RTP.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low (continued)

The Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Function with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is ≥ 26% RTP. This Function is not required when THERMAL POWER is < 26% RTP, since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

10. Reactor Mode Switch-Shutdown Position

The Reactor Mode Switch—Shutdown Position Function provides signals, via the manual scram logic channels, to each of the four RPS logic channels, which are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The reactor mode switch is a single switch with four channels, each of which provides input into one of the RPS logic channels.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on reactor mode switch position.

Four channels of Reactor Mode Switch—Shutdown Position. Function, with two channels in each trip system, are available and required to be OPERABLE. The Reactor Mode Switch—Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Manual Scram

The Manual Scram push button channels provide signals, via the manual scram logic channels, to each of the four RPS logic channels, which are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is one Manual Scram push button channel for each of the four RPS logic channels. In order to cause a scram it is necessary that at least one channel in each trip system be actuated.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of Manual Scram with two channels in each trip system arranged in a one-out-of-two logic are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

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

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

12 hours has been shown to be acceptable (Refs. 9, 15 and 16) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

As noted, Action A.2 is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, Required Action A.1 must be satisfied, and is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and entry into Condition C, as well as entry into Condition A for each channel.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in References 9, 15 or 16 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in References 9, 15 and 16 which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in).

If this action would result in a scram, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram), Condition D must be entered and its Required Action taken.

As noted, Condition B is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-out-of-4 Voter (Function 2.e) and other non-APRM channels for which Condition B applies. For an inoperable APRM channel, Required Action A.1 must be satisfied, and is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of a Function in more than one required APRM channel results in loss of trip capability for that Function and entry into Condition C, as well as entry into Condition A for each channel. Because Conditions A and C provide Required Actions that are appropriate for the inoperability of APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f, and because

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

these Functions are not associated with specific trip systems as are the APRM 2-out-of-4 Voter and other non-APRM channels, Condition B does not apply.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve-Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 8 (Turbine Stop Valve—Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

E.1, F.1, G.1, and J.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Actions E.1 and J.1 are consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

I.1 and I.2

Required Actions I.1 and I.2 are intended to ensure that appropriate actions are taken if more than two inoperable or bypassed OPRM channels result in not maintaining OPRM trip capability.

In the 4-OPRM channel configuration, any 'two' of the OPRM channels out of the total of four and one 2-out-of-4 voter channels in each RPS trip system are required to function for the OPRM safety trip function to be accomplished. Therefore, three OPRM channels assures at least two OPRM channels can provide trip inputs to the 2-out-of-4 voter channels even in the event of a single OPRM channel failure, and the minimum of two 2-out-of-4 voter channels per RPS trip system assures at least one voter channel will be operable per RPS trip system even in the event of a single voter channel failure.

References 15 and 16 justified use of alternate methods to detect and suppress oscillations under limited conditions. The alternate methods are consistent with the guidelines identified in Reference 20. The

(continued)

BASES

ACTIONS

I.1 and I.2 (continued)

alternate-methods procedures require increased operator awareness and monitoring for neutron flux oscillations when operating in the region where oscillations are possible. If operator observes indications of oscillation, as described in Reference 20, the operator will take the actions described by procedures, which include manual scram of the reactor. The power/flow map regions where oscillations are possible are developed based on the methodology in Reference 22. The applicable regions are contained in the COLR.

The alternate methods would adequately address detection and mitigation in the event of thermal hydraulic instability oscillations. Based on industry operating experience with actual instability oscillations, the operator would be able to recognize instabilities during this time and take action to suppress them through a manual scram. In addition, the OPRM system may still be available to provide alarms to the operator if the onset of oscillations were to occur.

The 12-hour allowed Completion Time for Required Action I.1 is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. Based on the small probability of an instability event occurring at all, the 12 hours is judged to be reasonable.

The 120-day allowed Completion Time, the time that was evaluated in References 15 and 16, is considered adequate because with operation minimized in regions where oscillations may occur and implementation of the alternate methods, the likelihood of an instability event that could not be adequately handled by the alternate methods during this 120-day period was negligibly small.

The primary purpose of Required Actions I.1 and I.2 is to allow an orderly completion, without undue impact on plant operation, of design and verification activities required to correct unanticipated equipment design or functional problems that cause OPRM Trip Function INOPERABILITY in all APRM channels that cannot reasonably be corrected by normal maintenance or repair actions. These Required Actions are not intended and were not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status.

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BASES

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 9, 15 and 16) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

SR 3.3.1.1.1 and SR 3.3.1.1.2

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument
channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria, which are determined by the plant staff based on an investigation of a combination of the channel instrument uncertainties, may be used to support this parameter comparison and include indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit, and does not necessarily indicate the channel is Inoperable.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.1 and SR 3.3.1.1.2 (continued)

The Frequency of once every 12 hours for SR 3.3.1.1.1 is based upon operating experience that demonstrates that channel failure is rare. The Frequency of once every 24 hours for SR 3.3.1.1.2 is based upon operating experience that demonstrates that channel failure is rare and the evaluation in References 15 and 16. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.3

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8.

A restriction to satisfying this SR when < 23% RTP is provided that requires the SR to be met only at ≥ 23% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 23% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR, LHGR and APLHGR). At ≥ 23% RTP, the Surveillance is required to have been satisfactorily performed within the last 7 days, in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 23% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 23% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 9).

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A Frequency of 7 days provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis of Reference 9. (The Manual Scram Function's CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions' Frequencies.)

SR 3.3.1.1.6 and SR 3.3.1.1.7

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status.

The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a neutron flux region without adequate indication. The overlap is demonstrated prior to fully withdrawing the SRMs from the core. Demonstrating the overlap prior to fully withdrawing the SRMs from the core is required to ensure the SRMs are on-scale for the overlap demonstration.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (by initiating a rod block) if adequate overlap is not maintained. Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. Overlap between SRMs and IRMs similarly exists when, prior to fully withdrawing the SRMs from the core, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block.

As noted, SR 3.3.1.1.7 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channels that are required in the current MODE or condition should be declared inoperable.

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles that are either measured by the Traversing Incore Probe (TIP) System at all functional locations or calculated for TIP locations that are not functional. The methodology used to develop the power distribution limits considers the uncertainty for both measured and calculated local flux profiles. This methodology assumes that all the TIP locations are functional for the first LPRM calibration following a refueling outage, and a minimum of 25 functional TIP locations for subsequent LPRM calibrations. The calibrated LPRMs establish the relative local flux profile for appropriate representative input to the APRM System. The 1000 MWD/MT Frequency is based on operating experience with LPRM sensitivity changes.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

S R 3.3.1.1.9 and SR 3.3.1.1.14

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.

SR 3.3.1.1.9 is modified by a Note that provides a general exception to the definition of CHANNEL FUNCTIONAL TEST. This exception is necessary because the design of instrumentation does not facilitate functional testing of all required contacts of the relay, which input into the combinational logic. (Reference 10) Performance of such a test could
result in a plant transient or place the plant in an undo risk situation. Therefore, for this SR, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of the relay, which inputs into the combinational logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.1.1.15. This is acceptable because operating experience shows that the contacts not tested during inputs into the combinational logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.1.1.15. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

The 24 month Frequency of SR 3.3.1.1.14 is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.1.1.10, SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.18

A CHANNEL CALIBRATION verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.10, SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.18 (continued)

Note 1 for SR 3.3.1.1.18 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.3) and the 1000 MWD/MT LPRM calibration against the TIPs (SR 3.3.1.1.8).

A Note is provided for SR 3.3.1.1.11 that requires the IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A second note is provided for SR 3.3.1.1.18 that requires that the recirculation flow (drive flow) transmitters, which supply the flow signal to the APRMs, be included in the SR for Functions 2.b and 2.f. The APRM Simulated Thermal Power-High Function (Function 2.b) and the OPRM Trip Function (Function 2.f) both require a valid drive flow signal. The APRM Simulated Thermal Power-High Function uses drive flow to vary the trip setpoint. The OPRM Trip Function uses drive flow to automatically enable or bypass the OPRM Trip output to the RPS. A CHANNEL CALIBRATION of the APRM drive flow signal requires both calibrating the drive flow transmitters and the processing hardware in the APRM equipment. SR 3.3.1.1.20 establishes a valid drive flow / core flow relationship. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power-High Function and the OPRM Trip Function.

The Frequency of 184 days for SR 3.3.1.1.11, 92 days for SR 3.3.1.1.12 and 24 months for SR 3.3.1.1.13 and SR 3.3.1.1.18 is based upon the assumptions in the determination of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. For the APRM Functions, this test supplements the automatic self-test functions that operate continuously in the APRM and voter channels. The scope of the APRM CHANNEL FUNCTIONAL TEST is that which is necessary to test the hardware. Software controlled functions are tested as part of the initial verification and validation and are only incidentally tested as part of the surveillance testing. Automatic self-test functions check the EPROMs in which the software-controlled logic is defined. Changes in the EPROMs will be detected by the self-test function and alarmed via the APRM trouble alarm. SR 3.3.1.1.1 for the APRM functions includes a step to confirm that the automatic self-test function is still operating.

The APRM CHANNEL FUNCTIONAL TEST covers the APRM channels (including recirculation flow processing -- applicable to Function 2.b and the auto-enable portion of Function 2.f only), the 2-out-of-4 Voter channels, and the interface connections into the RPS trip systems from the voter channels.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 184-day Frequency of SR 3.3.1.1.12 is based on the reliability analyses of References 15 and 16. (NOTE: The actual voting logic of the 2-out-of-4 Voter Function is tested as part of SR 3.3.1.1.15. The auto-enable setpoints for the OPRM Trip are confirmed by SR 3.3.1.1.19.)

A Note is provided for Function 2.a that requires this SR to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM Function cannot be performed in MODE 1 without utilizing jumpers or lifted leads. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2.

A second Note is provided for Functions 2.b and 2.f that clarifies that the CHANNEL FUNCTIONAL TEST for Functions 2.b and 2.f includes testing of the recirculation flow processing electronics, excluding the flow transmitters.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The LOGIC SYSTEM FUNCTIONAL TEST for APRM Function 2.e simulates APRM and OPRM trip conditions at the 2-out-of-4 Voter channel inputs to check all combinations of two tripped inputs to the 2-out-of-4 logic in the voter channels and APRM-related redundant RPS relays.

The 24 month Frequency is based on the need to perform portions of this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 26% RTP. This is performed by a Functional check that ensures the scram feature is not bypassed at ≥ 26% RTP. Because main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the opening of the main turbine bypass valves must not cause the trip Function to be bypassed when Thermal Power is > 26% RTP.

If any bypass channel's trip function is nonconservative (i.e., the Functions are bypassed at ≥ 26% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.16 (continued)

The Frequency of 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.17

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference 11.

RPS RESPONSE TIME for the APRM 2-out-of-4 Voter Function (2.e) includes the APRM Flux Trip output relays and the OPRM Trip output relays of the voter and the associated RPS relays and contactors. (Note: The digital portion of the APRM, OPRM and 2-out-of-4 Voter channels are excluded from RPS RESPONSE TIME testing because self-testing and calibration checks the time base of the digital electronics. Confirmation of the time base is adequate to assure required response times are met. Neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. See References 12 and 13).

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

RPS RESPONSE TIME tests are conducted on an 24 month STAGGERED TEST BASIS. Note 3 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function because channels are arranged in pairs.

This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.17 (continued)

SR 3.3.1.1.17 for Function 2.e confirms the response time of that function, and also confirms the response time of components common to Function 2.e and other RPS Functions. (Reference 14)

Note 3 allows the STAGGERED TEST BASIS Frequency for Function 2.e to be determined based on 8 channels rather than the 4 actual 2-out-of-4 Voter channels. The redundant outputs from the 2-out-of-4 Voter channel (2 for APRM trips and 2 for OPRM trips) are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels for application of SR 3.3.1.1.17, so N = 8. The note further requires that testing of OPRM and APRM outputs from a 2-out-of-4 Voter be alternated. In addition to these commitments, References 15 and 16 require that the testing of inputs to each RPS Trip System alternate.

Combining these frequency requirements, an acceptable test sequence is one that:

a. Tests each RPS Trip System interface every other cycle,

b. Alternates the testing of APRM and OPRM outputs from any specific 2-out-of-4 Voter Channel,

c. Alternates between divisions at least every other test cycle.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.17 (continued)

The testing sequence shown in the table below is one sequence that satisfies these requirements.

Function 2.e Testing Sequence for SR 3.3.1.1.17

24-Month Cycle	Voter Output Tested	"Staggering"					
		Voter A1 Output	Voter A2 Output	Voter B1 Output	Voter B2 Output	RPS Trip System	Division
1st	OPRM A1	OPRM				A	1
2nd	APRM B1			APRM		B	1
3rd	OPRM A2		OPRM			A	2
4th	APRM B2				APRM	B	2
5th	APRM A1	APRM				A	1
6th	OPRM B1			OPRM		B	1
7th	APRM A2		APRM			A	2
8th	OPRM B2				OPRM	B	2

After 8 cycles, the sequence repeats.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-out-of-4 Voter channel for that Function and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. The RPS relay testing frequency is twice the frequency justified by References 15 and 16.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.19

This surveillance involves confirming the OPRM Trip auto-enable setpoints. The auto-enable setpoint values are considered to be nominal values as discussed in Reference 21. This surveillance ensures that the OPRM Trip is enabled (not bypassed) for the correct values of APRM Simulated Thermal Power and recirculation drive flow. Other surveillances ensure that the APRM Simulated Thermal Power and recirculation drive flow properly correlate with THERMAL POWER (SR 3.3.1.1.2) and core flow (SR 3.3.1.1.20), respectively.

If any auto-enable setpoint is nonconservative (i.e., the OPRM Trip is bypassed when APRM Simulated Thermal Power ≥ 25% and recirculation drive flow ≤ value equivalent to the core flow value defined in the COLR, then the affected channel is considered inoperable for the OPRM Trip Function. Alternatively, the OPRM Trip auto-enable setpoint(s) may be adjusted to place the channel in a conservative condition (not bypassed). If the OPRM Trip is placed in the not-bypassed condition, this SR is met, and the channel is considered OPERABLE.

For purposes of this surveillance, consistent with Reference 21, the conversion from core flow values defined in the COLR to drive flow values used for this SR can be conservatively determined by a linear scaling assuming that 100% drive flow corresponds to 100 Mlb/hr core flow, with no adjustment made for expected deviations between core flow and drive flow below 100%.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.20

The APRM Simulated Thermal Power-High Function (Function 2.b) uses drive flow to vary the trip setpoint. The OPRM Trip Function (Function 2.f) uses drive flow to automatically enable or bypass the OPRM Trip output to RPS. Both of these Functions use drive flow as a representation of reactor core flow. SR 3.3.1.1.18 ensures that the drive flow transmitters and processing electronics are calibrated. This SR adjusts the recirculation drive flow scaling factors in each APRM channel to provide the appropriate drive flow/core flow alignment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.20 (continued)

The Frequency of 24 months considers that any change in the core flow to drive flow functional relationship during power operation would be gradual and the maintenance of the Recirculation System and core components that may impact the relationship is expected to be performed during refueling outages. This frequency also considers the period after reaching plant equilibrium conditions necessary to perform the test, engineering judgment of the time required to collect and analyze the necessary flow data, and engineering judgment of the time required to enter and check the applicable scaling factors in each of the APRM channels. This timeframe is acceptable based on the relatively small alignment errors expected, and the margins already included in the APRM Simulated Thermal Power – High and OPRM Trip Function trip – enable setpoints.

REFERENCES

1. FSAR, Figure 7.2-1.
2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
4. FSAR, Section 5.2.2.
5. FSAR, Chapter 15.
6. FSAR, Section 6.3.3.
7. Not used.
8. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.
9. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

BASES

REFERENCES (continued)

10. NRC Inspection and Enforcement Manual, Part 9900: Technical Guidance, Standard Technical Specification 1.0 Definitions, Issue date 12/08/86.

11. FSAR, Table 7.3-28.

12. NEDO-32291-A "System Analyses for Elimination of Selected Response Time Testing Requirements," October 1995.

13. NRC Safety Evaluation Report related to Amendment No. 171 for License No. NPF 14 and Amendment No. 144 License No. NPF 22.

14. NEDO 32291-A, Supplement 1, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1999.

15. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

16. NEDC-32410P-A Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

17. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

18. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

19. NEDO-32465-A, "BWR Owners' Group Long-Term Stability Detect and Suppress Solutions Licensing Basis Methodology and Reload Applications," August 1996.

20. BWROG Letter BWROG 9479, L. A. England (BWROG) to M. J. Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action," June 6, 1994.

BASES

REFERENCES (continued)

21. BWROG Letter BWROG 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), "Guidelines for Stability Option III 'Enable Region' (TAC M92882)," September 17, 1996.

22. EMF-CC-074(P)(A), Volume 4, "BWR Stability Analysis: Assessment of STAIF with Input from MICROBURN-B2."

23. GE Letter to PPL, GE-2005-EMC426, "Susquehanna 1 & 2 Minimum LPRM Input Requirement for NUMAC APRM 4-Channel Design," April 26, 2005.

Table B 3.3.1.1-1 (page 1 of 1)
RPS Instrumentation Sensor Diversity

Initiation Events	Scram Sensors for Initiating Events						
	RPV Variables				Anticipatory		Fuel
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
MSIV Closure	X		X			X	X
Turbine Trip (w/bypass)	X			X	X		X
Generator Trip (w/bypass)	X			X			X
Pressure Regulator Failure (primary pressure decrease) (MSIV closure trip)	X	X	X			X	X
Pressure Regulator Failure (primary pressure decrease) (Level 8 trip)	X				X		X
Pressure Regulator Failure (primary pressure increase)	X						X
Feedwater Controller Failure (high reactor water level)	X	X			X		X
Feedwater Controller Failure (low reactor water level)	X		X			X	
Loss of Condenser Vacuum	X				X	X	X
Loss of AC Power (loss of transformer)	X		X		X	X	
Loss of AC Power (loss of grid connections)	X		X	X	X	X	X

(a) Reactor Vessel Steam Dome Pressure—High
(b) Reactor Vessel Water Level—High, Level 8
(c) Reactor Vessel Water Level—Low, Level 3
(d) Turbine Control Valve Fast Closure
(e) Turbine Stop Valve—Closure
(f) Main Steam Isolation Valve—Closure
(g) Average Power Range Monitor Neutron Flux—High

B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater – Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The feedwater - main turbine high water level trip instrumentation is designed to detect a potential failure of the Feedwater Level Control System that causes excessive feedwater flow.

With excessive feedwater flow, the water level in the reactor vessel rises toward the high water level, Level 8 reference point, causing the trip of the three feedwater pump turbines and the main turbine.

Reactor Vessel Water Level—High, Level 8 signals are provided by level sensors that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level in the reactor vessel (variable leg). Three channels of Reactor Vessel Water Level—High, Level 8 instrumentation are provided as input to a two-out-of-three initiation logic that trips the three feedwater pump turbines and the main turbine. When the setpoint is exceeded, the channel sensor actuates, which then outputs a main feedwater and turbine trip signal to the trip logic.

A trip of the feedwater pump turbines limits further increase in reactor vessel water level by limiting further addition of feedwater to the reactor vessel. A trip of the main turbine and closure of the stop valves protects the turbine from damage due to water entering the turbine.

APPLICABLE SAFETY ANALYSES

The feedwater - main turbine high water level trip instrumentation is assumed to be capable of providing a turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1). The Level 8 trip indirectly initiates a reactor scram from the main turbine trip (above 26% RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Feedwater - main turbine high water level trip instrumentation satisfies Criterion 3 of the NRC Policy Statement. (Ref. 3)

LCO

The LCO requires three channels of the Reactor Vessel Water Level—High, Level 8 trip instrumentation to be OPERABLE to ensure that no single instrument failure will prevent the feedwater pump turbines and main turbine trip on a valid Level 8 signal. Two of the three channels are needed to provide trip signals in order for the feedwater - main turbine trips to occur. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.2.2.3. The Allowable Value is set to ensure that the thermal limits are not exceeded during the event. The actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter reaches the setpoint, the associated device changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

(continued)

BASES (continued)

APPLICABILITY

The feedwater - main turbine high water level trip instrumentation is required to be OPERABLE at ≥ 23% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases of LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists below 23% RTP; therefore, the requirements are only necessary when operating at or above this power level.

ACTIONS

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

A.1

With one channel inoperable, the remaining two OPERABLE channels can provide the required trip signal. However, overall instrumentation reliability is reduced because a single failure in one of the remaining channels concurrent with feedwater controller failure, maximum demand event, may result in the instrumentation not being able to perform its intended function. Therefore, continued operation is only allowed for a limited time with one channel inoperable. If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel must be placed in the tripped condition per Required Action A.1. Placing the

(continued)

BASES

ACTIONS

A.1 (continued)

inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in a feedwater or main turbine trip), Condition C must be entered and its Required Action taken.

If the failure only affects the trip function of a single main feed pump, an option is always available to remove the affected component from service and restore OPERABILITY. This is acceptable because removing the component from service performs the safety function.

The Completion Time of 7 days is based on the low probability of the event occurring coincident with a single failure in a remaining OPERABLE channel.

B.1

With two or more channels inoperable, the feedwater - main turbine high water level trip instrumentation cannot perform its design function (feedwater - main turbine high water level trip capability is not maintained). Therefore, continued operation is only permitted for a 2 hour period, during which feedwater - main turbine high water level trip capability must be restored. The trip capability is considered maintained when sufficient channels are OPERABLE or in trip such that the feedwater - main turbine high water level trip logic will generate a trip signal on a valid signal. This requires two channels to each be OPERABLE or in trip. If the required channels cannot be restored to OPERABLE status or placed in trip, Condition C must be entered and its Required Action taken.

If the failure only affects the trip function of a single main feed pump, an option is always available to remove the affected component from service and restore OPERABILITY. This is acceptable because removing the component from service performs the safety function.

(continued)

BASES

ACTIONS

B.1 (continued)

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of feedwater - main turbine high water level trip instrumentation occurring during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1

With the required channels not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 23% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 23% RTP results in sufficient margin to the required limits, and the feedwater - main turbine high water level trip instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 23% RTP from full power conditions in an orderly manner and without challenging plant systems.

If the failure only affects the trip function of a single main feed pump, an option is always available to remove the affected component from service and restore OPERABILITY. This is acceptable because removing the component from service performs the safety function.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains feedwater - main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

taken. This Note is based on the reliability analysis (Ref. 2) assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the feedwater pump turbines and main turbine will trip when necessary.

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels, or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria which are determined by the plant staff based on an investigation of a combination of the channel instrument uncertainties may be used to support this parameter comparison and include indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit, and does not necessarily indicate the channel is Inoperable.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of channel status during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.2.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2.2 (continued)

The Frequency of 92 days is based on reliability analysis (Ref. 2).

This SR is modified by two Notes. Note 1 provides a general exception to the definition of CHANNEL FUNCTIONAL TEST. This exception is necessary because the design of instrumentation does not facilitate functional testing of all required contacts of the relays which input into the combinational logic. (Reference 4) Performance of such a test could result in a plant transient or place the plant in an undo risk situation. Therefore, for this SR, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of the relay which inputs into the combinational logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.2.2.4. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

Note 2 provides a second specific exception to the definition of CHANNEL FUNCTIONAL TEST. For the Feedwater - Main Turbine High Water Level Trip Function, certain required channel relays are not included in the performance of the CHANNEL FUNCTIONAL TEST. These exceptions are necessary because the circuit design does not facilitate functional testing of the entire channel through to the coil of the relay which enters the combinational logic. (Reference 4) Specifically, testing of all required relays would require lifting of leads and inserting test equipment which could lead to unplanned transients. Therefore, for this circuit, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the actuation of circuit devices up to the point where further testing could result in an unplanned transient. (References 5 and 6) The required relays not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.2.2.4. This exception is acceptable because operating experience shows that the devices not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2.3

CHANNEL CALIBRATION verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.2.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the feedwater - main turbine valves is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a valve is incapable of operating, the associated instrumentation would also be inoperable. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. FSAR, Section 15.1.2.

2. GENE-770-06-1, "Bases for Changes to Surveillance Test Selected Instrumentation Technical Specifications," February 1991.

3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132)

4. NRC Inspection and Enforcement Manual, Part 9900: Technical Guidance, Standard Technical Specification Section 1.0 Definitions, Issue date 12/08/86.

(continued)

BASES

REFERENCES (continued)

5. PLA-2618: NRC Inspection Reports 50-387/85-28 and 50-388/85-23.

6. NRC Region I Combined Inspection 50-387/90-20; 50-388/90-20.

B 3.3 INSTRUMENTATION

B 3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

BASES

BACKGROUND

The EOC-RPT instrumentation initiates a recirculation pump trip (RPT) to reduce the peak reactor pressure and power resulting from turbine trip or generator load rejection transients to provide additional margin to core thermal MCPR Safety Limits (SLs).

The need for the additional negative reactivity in excess of that normally inserted on a scram reflects end of cycle reactivity considerations. Flux shapes at the end of cycle are such that the control rods may not be able to ensure that thermal limits are maintained by inserting sufficient negative reactivity during the first few feet of rod travel upon a scram caused by Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure—Low or Turbine Stop Valve (TSV)—Closure. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity at a faster rate than the control rods can add negative reactivity.

The EOC-RPT instrumentation, as shown in Reference 1, is composed of sensors that detect initiation of closure of the TSVs or fast closure of the TCVs, combined with relays, logic circuits, and fast acting circuit breakers that interrupt power from the recirculation pump motor generator (MG) set generators to each of the recirculation pump motors. When the setpoint is reached, the channel output relay actuates, which then outputs an EOC-RPT signal to the trip logic. When the RPT breakers trip open, the recirculation pumps coast down under their own inertia. The EOC-RPT has two identical trip systems, either of which can actuate an RPT.

Each EOC-RPT trip system is a two-out-of-two logic for each Function; thus, either two TSV—Closure or two TCV Fast Closure, Trip Oil Pressure—Low signals are required for a trip system to actuate. The Turbine Stop Valve - Closure functions such that:

(1) The closing of one Turbine Stop Valve will not cause an RPT trip.

(continued)

BASES

BACKGROUND (continued)

(2) The closing of two Turbine Stop Valves may or may not cause an RPT trip depending on which stop valves are closed.

(3) The closing of three or more Turbine Stop Valves will always yield an RPT trip.

If either trip system actuates, both recirculation pumps will trip. There are two RPT breakers in series per recirculation pump. One trip system trips one of the two RPT breakers for each recirculation pump, and the second trip system trips the other RPT breaker for each recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The TSV—Closure and the TCV Fast Closure, Trip Oil Pressure—Low Functions are designed to trip the recirculation pumps in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux, and pressure transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that take credit for EOC-RPT, are summarized in References 2 and 3.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps after initiation of closure movement of either the TSVs or the TCVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than a scram alone, resulting in an increased margin to the MCPR SL. Alternatively, MCPR limits for an inoperable EOC-RPT, as specified in the COLR, are sufficient to mitigate pressurization transient effects. The EOC-RPT function is automatically disabled when turbine first stage pressure is < 26% RTP.

EOC-RPT instrumentation satisfies Criterion 3 of the NRC Policy Statement. (Ref. 6)

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.2. The actual setpoint is calibrated consistent with applicable

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

setpoint methodology assumptions. Channel OPERABILITY also includes the associated RPT breakers. Each channel (including the associated RPT breakers) must also respond within its assumed response time.

Allowable Values are specified for each EOC-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the analytical limit assumed in the transient and accident analysis in order to account for instrument uncertainties appropriate to the Function. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., TSV position), and when the measured output value of the process parameter reaches the setpoint, the associated device changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

Alternatively, since this instrumentation protects against a MCPR SL violation, with the instrumentation inoperable, modifications to the MCPR limits (LCO 3.2.2) may be applied to allow this LCO to be met. The MCPR penalty for the EOC-RPT inoperable condition is specified in the COLR.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Turbine Stop Valve—Closure

Closure of the TSVs and a main turbine trip result in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TSV—Closure in anticipation of the transients that would result from closure of these valves. EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient. Closure of the TSVs is determined by measuring the position of each valve. There are two separate position switches associated with each stop valve, the signal from each switch being assigned to a separate trip channel. The logic for the TSV—Closure Function is such that two or more TSVs must be closed to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 26% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 26% RTP. Four channels of TSV—Closure, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV—Closure Allowable Value is selected to detect imminent TSV closure.

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is ≥ 26% RTP. Below 26% RTP, the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor (APRM) Fixed Neutron Flux—High Functions of the Reactor Protection System (RPS) are adequate to maintain the necessary safety margins.

Turbine Control Valve Fast Closure, Trip Oil Pressure—Low

Fast closure of the TCVs during a generator load rejection results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TCV Fast Closure, Trip Oil Pressure—Low in anticipation of the transients that would result from the closure of these valves. The EOC-RPT decreases reactor power and aids the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Turbine Control Valve Fast Closure, Trip Oil Pressure—Low (continued)

reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Fast closure of the TCVs is determined by measuring the electrohydraulic control fluid pressure at each control valve. There is one pressure instrument associated with each control valve, and the signal from each instrument is assigned to a separate trip channel. The logic for the TCV Fast Closure, Trip Oil Pressure—Low Function is such that two or more TCVs must be closed (pressure instrument trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 26% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure) the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 26% RTP. Four channels of TCV Fast Closure, Trip Oil Pressure—Low, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TCV Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

This protection is required consistent with the safety analysis whenever THERMAL POWER is ≥ 26% RTP. Below 26% RTP, the Reactor Vessel Steam Dome Pressure—High and the APRM Fixed Neutron Flux—High Functions of the RPS are adequate to maintain the necessary safety margins.

ACTIONS

A Note has been provided to modify the ACTIONS related to EOC-RPT instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for

(continued)

BASES

ACTIONS (continued)

inoperable EOC-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable EOC-RPT instrumentation channel.

A.1, A.2 and A.3

With one or more channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Actions B.1 and B.2 Bases), the EOC-RPT System is capable of performing the intended function. However, the reliability and redundancy of the EOC-RPT instrumentation is reduced such that a single failure in the remaining trip system could result in the inability of the EOC-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore compliance with the LCO. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of an EOC-RPT, 72 hours is provided to restore the inoperable channels (Required Action A.1). Alternately, the inoperable channels may be placed in trip (Required Action A.2) or Required Action A.3 MCPR Limits for inoperable EOC-RPT can be applied since these would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT, or if the inoperable channel is the result of an inoperable breaker), Condition C must be entered and its Required Actions taken.

B.1 and B.2

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining EOC-RPT trip capability. A Function is considered to be maintaining EOC-RPT trip

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

capability when sufficient channels are OPERABLE or in trip, such that the EOC-RPT System will generate a trip signal from the given Function on a valid signal and both recirculation pumps can be tripped. This requires two channels of the Function in the same trip system, to each be OPERABLE or in trip, and the associated RPT breakers to be OPERABLE or in trip. Alternately, Required Action B.2 requires the MCPR limit for inoperable EOC-RPT, as specified in the COLR, to be applied. This also restores the margin to MCPR assumed in the safety analysis.

The 2 hour Completion Time is sufficient time for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of the EOC-RPT instrumentation during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 26% RTP within 4 hours. Alternately, the associated recirculation pump may be removed from service, since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER to < 26% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains EOC-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) assumption of the average

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

SR 3.3.4.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

This SR is modified by a Note that provides a general exception to the definition of CHANNEL FUNCTIONAL TEST. This exception is necessary because the design of instrumentation does not facilitate functional testing of all required contacts of the relay which input into the combinational logic. (Reference 7) Performance of such a test could result in a plant transient or place the plant in an undo risk situation. Therefore, for this SR, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of the relay which inputs into the combinational logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.4.1.3. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

The Frequency of 92 days is based on reliability analysis of Reference 5.

SR 3.3.4.1.2

CHANNEL CALIBRATION verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.2 (continued)

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

SR 3.3.4.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would also be inoperable.

The 24 month Frequency is based on the need to perform portions of this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.4.1.4

This SR ensures that an EOC-RPT initiated from the TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 26% RTP. This is performed by a Functional check that ensures the EOC-RPT Function is not bypassed. Because increasing the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure) the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 26% RTP. If any functions are bypassed at ≥ 26% RTP, either due to open main turbine bypass valves or other reasons, the affected TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.4 (continued)

in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met with the channel considered OPERABLE.

The Frequency of 24 months has shown that channel bypass failures between successive tests are rare.

SR 3.3.4.1.5

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference 5.

A Note to the Surveillance states that breaker interruption time may be assumed from the most recent performance of SR 3.3.4.1.6. This is allowed since the time to open the contacts after energization of the trip coil and the arc suppression time are short and do not appreciably change, due to the design of the breaker opening device and the fact that the breaker is not routinely cycled.

EOC-RPT SYSTEM RESPONSE TIME tests are conducted on an 24 month STAGGERED TEST BASIS. For this SR, STAGGERED TEST BASIS means that each 24 month test shall include at least the logic of one type of channel input, turbine control valve, fast closure or turbine stop valve closure such that both types of channel inputs are tested at least once per 48 months. Response times cannot be determined at power because operation of final actuated devices is required. Therefore, the 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components that cause serious response time degradation, but not channel failure, are infrequent occurrences.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.6

This SR ensures that the RPT breaker interruption time (arc suppression time plus time to open the contacts) is provided to the EOC-RPT SYSTEM RESPONSE TIME test. The 60 month Frequency of the testing is based on the difficulty of performing the test and the reliability of the circuit breakers.

REFERENCES

1. FSAR, Figure 7.2-1-4 (EOC-RPT logic diagram).
2. FSAR, Sections 15.2 and 15.3.
3. FSAR, Sections 7.1 and 7.6.
4. GENE-770-06-1, "Bases For Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," February 1991.
5. FSAR Table 7.6-10.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 32193).
7. NRC Inspection and Enforcement Manual, Part 9900: Technical Guidance, Standard Technical Specification Section 1.0 Definitions, Issue date 12/08/86.

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

BACKGROUND

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

The isolation instrumentation includes the sensors, relays, and instruments that are necessary to cause initiation of primary containment and reactor coolant pressure boundary (RCPB) isolation. When the setpoint is reached, the sensor actuates, which then outputs an isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logics are (a) reactor vessel water level, (b) area ambient and emergency cooler temperatures, (c) main steam line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) condenser vacuum, (f) main steam line pressure, (g) high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) steam line Δ pressure, (h) SGTS Exhaust radiation, (i) HPCI and RCIC steam line pressure, (j) HPCI and RCIC turbine exhaust diaphragm pressure, (k) reactor water cleanup (RWCU) differential flow and high flow, (l) reactor steam dome pressure, and (m) drywell pressure. Redundant sensor input signals from each parameter are provided for initiation of isolation. The only exception is SLC System initiation. In addition, manual isolation of the logics is provided.

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

(continued)

BASES

BACKGROUND (continued)

1. Main Steam Line Isolation

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

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

2. Primary Containment Isolation

Most Primary Containment Isolation Functions receive inputs from four channels. The outputs from these channels are arranged into two two-out-of-two logic trip systems. One trip system initiates isolation of all inboard primary containment isolation valves, while the other trip system initiates isolation of all outboard primary containment isolation valves. Each logic closes one of the two valves on each penetration, so that operation of either logic isolates the penetration.

The exceptions to this arrangement are as follows. Hydrogen and Oxygen Analyzers, which isolate Division I Analyzer on a Division I isolation signal, and Division II Analyzer on a Division II isolation signal. This is to ensure monitoring capability is not lost. Chilled Water to recirculation pumps and Liquid Radwaste Collection System isolation valves where both inboard and outboard valves will isolate on either

(continued)

BASES

BACKGROUND

2. Primary Containment Isolation (continued)

division providing the isolation signal. Traversing incore probe ball valves and the instrument gas to the drywell to suppression chamber vacuum breakers only have one isolation valve and receives a signal from only one division.

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

Most Functions that isolate HPCI and RCIC receive input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems in each isolation group is connected to one of the two valves on each associated penetration.

The exceptions are the HPCI and RCIC Turbine Exhaust Diaphragm Pressure—High and Steam Supply Line Pressure—Low Functions. These Functions receive inputs from four turbine exhaust diaphragm pressure and four steam supply pressure channels for each system. The outputs from the turbine exhaust diaphragm pressure and steam supply pressure channels are each connected to two two-out-of-two trip systems. Each trip system isolates one valve per associated penetration.

5. Reactor Water Cleanup System Isolation

The Reactor Vessel Water Level—Low Low, Level 2 Isolation Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems. The Differential Flow—High, Flow— High, and SLC System Initiation Functions receive input from two channels, with each channel in one trip system using a one-out-of-one logic. The temperature isolations are divided into three Functions. These Functions are Pump Area, Penetration Area, and Heat Exchanger Area. Each area is monitored by two temperature monitors, one for each trip system. These are configured so that any one input will trip the associated trip system. Each of the two trip systems is connected to one of the two valves on each RWCU penetration.

(continued)

BASES

BACKGROUND (continued)

6. Shutdown Cooling System Isolation

The Reactor Vessel Water Level—Low, Level 3 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected to two two-out-of-two trip systems. The Reactor Vessel Pressure—High Function receives input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems is connected to one of the two valves on each shutdown cooling penetration.

7. Traversing Incore Probe System Isolation

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

When either Isolation Function actuates, the TIP drive mechanisms will withdraw the TIPs, if inserted , and close the inboard TIP System isolation ball valves when the proximity probe senses the TIPs are withdrawn into the shield. The TIP System isolation ball valves are only open when the TIP System is in use. The outboard TIP System isolation valves are manual shear valves.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases for more detail of the safety analyses.

Primary containment isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement. (Ref. 8) Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPERABILITY of the primary containment instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints The OPERABILITY of the primary containment instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where appropriate.

Allowable Values are specified for each Primary Containment Isolation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL
CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter reaches the setpoint, the associated device changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

The penetrations which are isolated by the below listed functions can be determined by referring to the PCIV Table found in the Bases of LCO 3.6.1.3, "Primary Containment Isolation Valves."

Main Steam Line Isolation

1.a. Reactor Vessel Water Level—Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level—Low Low Low, Level 1 Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low Low, Level 1 Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 1). The isolation of the MSLs on Level 1 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four level instruments that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low Low, Level 1 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Level 1 Allowable Value (LCO 3.3.5.1) to ensure that the MSLs isolate on a potential loss of coolant accident (LOCA) to prevent offsite and control room doses from exceeding regulatory limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b. Main Steam Line Pressure—Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure—Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 2). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below 785 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 23% RTP.)

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

The Main Steam Line Pressure—Low trip will only occur after a 500 milli-second time delay to prevent any spurious isolations.

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization. The Main Steam Line Pressure—Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 2).

1.c. Main Steam Line Flow—High

Main Steam Line Flow—High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow—High Function is directly assumed in the analysis of the main steam line break (MSLB) (Ref. 1). The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c. Main Steam Line Flow—High (continued)

cladding temperature remains below the limits of 10 CFR 50.46 and offsite and control room doses do not exceed regulatory limits.

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

1.d. Condenser Vacuum—Low

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

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

Condenser vacuum pressure signals are derived from four pressure instruments that sense the pressure in the condenser. Four channels of Condenser Vacuum—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3 when all main turbine stop valves (TSVs) are closed, since the potential for condenser overpressurization is minimized. Switches are provided to manually bypass the channels when all TSVs are closed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.e. Reactor Building Main Steam Tunnel Temperature—High

Reactor Building Main Steam Tunnel temperature is provided to detect a leak in the RCPB and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the FSAR, since bounding analyses are performed for large breaks, such as MSLBs.

Area temperature signals are initiated from thermocouples located in the area being monitored. Four channels of Reactor Building Main Steam Tunnel Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The reactor building main steam tunnel temperature trip will only occur after a one second time delay.

The temperature monitoring Allowable Value is chosen to detect a leak equivalent to approximately 25 gpm of water.

1.f. Manual Initiation

The Manual Initiation push button channels introduce signals into the MSL isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for the overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four push buttons for the logic, two manual initiation push button per trip system. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Two channels of Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the MSL isolation automatic Functions are required to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Primary Containment Isolation

2.a. Reactor Vessel Water Level - Low, Level 3

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 3 supports actions to ensure that offsite and control room dose regulatory limits are not exceeded. The Reactor Vessel Water Level—Low, Level 3 Function associated with isolation is implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from level instruments that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low, Level 3 Allowable Value was chosen to be the same as the RPS Level 3 scram Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown.

2.b. Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 2 supports actions to ensure that offsite and control room dose regulatory limits are not exceeded. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with isolation is implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from level instruments that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Reactor Vessel Water Level - Low Low, Level 2 (continued)

are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Level 2 Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA.

2.c. Reactor Vessel Water Level—Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 1 supports actions to ensure the offsite and control room dose regulatory limits are not exceeded. The Reactor Vessel Water Level - Low Low Low, Level 1 Function associated with isolation is implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor vessel water level signals are initiated from four level instruments that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level-Low Low Low, Level 1 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Level 1 Allowable Value (LCO 3.3.5.1) to ensure that the associated penetrations isolate on a potential loss of coolant accident (LOCA) to prevent offsite and control room doses from exceeding regulatory limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.d. Drywell Pressure—High

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

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

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

2.e. SGTS Exhaust Radiation—High

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

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

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.f. Manual Initiation

The Manual Initiation push button channels introduce signals into the primary containment isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two push buttons for the logic, one manual initiation push button per trip system. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Two channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the Primary Containment Isolation automatic Functions are required to be OPERABLE.

High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Isolation

3.a., 4.a. HPCI and RCIC Steam Line Δ Pressure—High

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

The HPCI and RCIC Steam Line Δ Pressure — High signals are initiated from instruments (two for HPCI and two for RCIC) that are connected

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a., 4.a. HPCI and RCIC Steam Line Δ Pressure—High (continued)

to the system steam lines. Two channels of both HPCI and RCIC Steam Line Δ pressure—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The steam line Δ Pressure - High will only occur after a 3 second time delay to prevent any spurious isolations.

The Allowable Values are chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event, and high enough to be above the maximum transient steam flow during system startup.

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

Low MSL pressure indicates that the pressure of the steam in the HPCI or RCIC turbine may be too low to continue operation of the associated system's turbine. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the FSAR. However, they also provide a diverse signal to indicate a possible system break. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations (Ref. 3).

The HPCI and RCIC Steam Supply Line Pressure—Low signals are initiated from instruments (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both HPCI and RCIC Steam Supply Line Pressure—Low Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

High turbine exhaust diaphragm pressure indicates that a release of steam into the associated compartment is possible. That is, one of two exhaust diaphragms has ruptured. These isolations are to prevent steam from entering the associated compartment and are not assumed in any transient or accident analysis in the FSAR. These instruments are included in the TS because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations (Ref. 3).

The HPCI and RCIC Turbine Exhaust Diaphragm Pressure—High signals are initiated from instruments (four for HPCI and four for RCIC) that are connected to the area between the rupture diaphragms on each system's turbine exhaust line. Four channels of both HPCI and RCIC Turbine Exhaust Diaphragm Pressure—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values is low enough to identify a high turbine exhaust pressure condition resulting from a diaphragm rupture, or a leak in the diaphragm adjacent to the exhaust line and high enough to prevent inadvertent system isolation.

3.d., 4.d. Drywell Pressure—High

High drywell pressure can indicate a break in the RCPB. The HPCI and RCIC isolation of the turbine exhaust vacuum breaker line is provided to prevent communication with the wetwell when high drywell pressure exists. A potential leakage path exists via the turbine exhaust. The isolation is delayed until the system becomes unavailable for injection (i.e., low steam supply line pressure). The isolation of the HPCI and RCIC turbine exhaust vacuum breaker line by Drywell Pressure—High is indirectly assumed in the FSAR accident analysis because the turbine exhaust vacuum breaker line leakage path is not assumed to contribute to offsite doses and is provided for long term containment isolation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d., 4.d. Drywell Pressure-High (continued)

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

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

3.e., 3.f., 3.g., 4.e., 4.f., 4.g., HPCI and RCIC Area and Emergency Cooler Temperature-High

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

Area and Emergency Cooler Temperature—High signals are initiated from thermocouples that are appropriately located to protect the system that is being monitored. Two instruments monitor each area. Two channels for each HPCI and RCIC Area and Emergency Cooler Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The HPCI and RCIC Pipe Routing area temperature trips will only occur after a 15 minute time delay to prevent any spurious temperature isolations due to short temperature increases and allows operators sufficient time to determine which system is leaking. The other ambient temperature trips will only occur after a one second time delay to prevent any spurious temperature isolations.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e., 3.f., 3.g., 4.e., 4.f., 4.g., HPCI and RCIC Area and Emergency Cooler Temperature—High (continued)

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm, and high enough to avoid trips at expected operating temperature.

3.h., 4.h. Manual Initiation

The Manual Initiation push button channels introduce signals into the HPCI and RCIC systems' isolation logics that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for these Functions. They are retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There is one manual initiation push button for each of the HPCI and RCIC systems. One isolation pushbutton per system will introduce an isolation to one of the two trip systems. There is no Allowable Value for these Functions, since the channels are mechanically actuated based solely on the position of the push buttons.

Two channels of both HPCI and RCIC Manual Initiation Functions are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the HPCI and RCIC systems' Isolation automatic Functions are required to be OPERABLE.

Reactor Water Cleanup System Isolation

5.a. RWCU Differential Flow—High

The high differential flow signal is provided to detect a break in the RWCU System. This will detect leaks in the RWCU System when area temperature would not provide detection (i.e., a cold leg break). Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when high differential flow is sensed to prevent exceeding offsite doses. A 45 second time delay is provided to prevent spurious trips during most RWCU operational transients. This Function is not assumed in any

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.a. RWCU Differential Flow—High (continued)

FSAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

The high differential flow signals are initiated from instruments that are connected to the inlet (from the recirculation suction) and outlets (to condenser and feedwater) of the RWCU System. Two channels of Differential Flow—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Differential Flow—High Allowable Value ensures that a break of the RWCU piping is detected.

5.b, 5.c, 5.d RWCU Area Temperatures—High

RWCU area temperatures are provided to detect a leak from the RWCU System. The isolation occurs even when small leaks have occurred and is diverse to the high differential flow instrumentation for the hot portions of the RWCU System. If the small leak continues without isolation, offsite dose limits may be reached. Credit for these instruments is not taken in any transient or accident analysis in the FSAR, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

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

The area temperature trip will only occur after a one second time to prevent any spurious temperature isolations.

The Area Temperature—High Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5.e. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 4). SLC System initiation signals are initiated from the two SLC pump start signals.

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

Two channels (one from each pump) of the SLC System Initiation Function are available and are required to be OPERABLE only in MODES 1, 2, and 3 which is consistent with the Applicability for the SLC System (LCO 3.1.7).

As noted (footnote (b) to Table 3.3.6.1-1), this Function is only required to close the outboard RWCU isolation valve trip systems.

5.f. Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some interfaces with the reactor vessel occurs to isolate the potential sources of a break. The isolation of the RWCU System on Level 2 supports actions to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with RWCU isolation is not directly assumed in the FSAR safety analyses because the RWCU System line break is bounded by breaks of larger systems (recirculation and MSL breaks are more limiting).

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from four level instruments that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.f. Reactor Vessel Water Level-Low Low, Level 2 (continued)

Reactor Vessel Water Level-Low Low, Level 2 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level-Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level-Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

5.g. RWCU Flow - High

RWCU Flow—High Function is provided to detect a break of the RWCU System. Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation is initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for this Function is not assumed in any FSAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks.

The RWCU Flow-High signals are initiated from two instruments. Two channels of RWCU Flow-High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The RWCU flow trip will only occur after a 5 second time delay to prevent spurious trips.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5.h. Manual Initiation

The Manual Initiation push button channels introduce signals into the RWCU System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two push buttons for the logic, one manual initiation push button per trip system. There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on the position of the push buttons.

Two channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RWCU System Isolation automatic Functions are required to be OPERABLE.

Shutdown Cooling System Isolation

6.a. Reactor Steam Dome Pressure-High

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

The Reactor Steam Dome Pressure—High signals are initiated from two instruments. Two channels of Reactor Steam Dome Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Function is only required to be OPERABLE in MODES 1, 2, and 3, since these are the only MODES in which the reactor can be pressurized with the exception of Special Operations LCO 3.10.1; thus, equipment protection is needed. The Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6.b. Reactor Vessel Water Level—Low, Level 3

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level—Low, Level 3 Function associated with RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the recirculation and MSL.

The RHR Shutdown Cooling System isolation on Level 3 supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from four level instruments that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels (two channels per trip system) of the Reactor Vessel Water Level—Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (c) to Table 3.3.6.1-1), only two channels of the Reactor Vessel Water Level—Low, Level 3 Function are required to be OPERABLE in MODES 4 and 5 (and must input into the same trip system), provided the RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.

The Reactor Vessel Water Level—Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level—Low, Level 3 Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level—Low, Level 3 Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering the reactor vessel level to the top of the fuel.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

In MODES 1 and 2, another isolation (i.e., Reactor Steam Dome Pressure—High) and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

6.c Manual Initiation

The Manual Initiation push button channels introduce signals to RHR Shutdown Cooling System isolation logic that is redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two push buttons for the logic, one manual initiation push button per trip system. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Two channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 3, 4, and 5, since these are the MODES in which the RHR Shutdown Cooling System Isolation automatic Function are required to be OPERABLE.

Traversing Incore Probe System Isolation

7.a Reactor Vessel Water Level - Low, Level 3

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 3 supports actions to ensure that offsite and control room dose regulatory limits are not exceeded. The Reactor Vessel Water Level - Low, Level 3 Function associated with isolation is implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Reactor Vessel Water Level - Low, Level 3 signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Two channels of Reactor Vessel Water Level - Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent isolation actuation. The isolation function is ensured by the manual shear valve in each penetration.

The Reactor Vessel Water Level - Low, Level 3 Allowable Value was chosen to be the same as the RPS Level 3 scram Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown.

7.b. Drywell Pressure - High

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

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Two channels of Drywell Pressure - High per Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent actuation. The isolation function is ensured by the manual shear valve in each penetration.

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

(continued)

BASES

ACTIONS

The ACTIONS are modified by two Notes. Note 1 allows penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated. Note 2 has been provided to modify the ACTIONS related to primary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable primary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable primary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 2.a, 2.d, 6.b, 7.a and 7.b and 24 hours for Functions other than Functions 2.a, 2.d, 6.b, 7.a and 7.b has been shown to be acceptable (Refs. 5 and 6) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant automatic isolation capability being lost for the associated penetration flow path(s). The MSL Isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For Functions 1.a, 1.b, 1.d, and 1.e, this would require both trip systems to have one channel OPERABLE or in trip. For Function 1.c, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. Therefore, this would require both trip systems to have one channel per location OPERABLE or in trip. For Functions 2.a, 2.b, 2.c, 2.d, 3.b, 3.c, 3.d, 4.b, 4.c, 4.d, 5.f, and 6.b, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 2.e, 3.a, 3.e, 3.f, 3.g, 4.a, 4.e, 4.f, 4.g, 5.a, 5.b, 5.c, 5.d, 5.e, 5.g, and 6.a, this would require one trip system to have one channel OPERABLE or in trip. The Condition does not include the Manual Initiation Functions (Functions 1.f, 2.f, 3.h, 4.h, 5.h, and 6.c), since they are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action A.1) is allowed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

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

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). Alternately, the associated MSLs may be isolated (Required Action D.1), and, if allowed (i.e., plant safety analysis allows operation with an MSL isolated), operation with that MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 6 hours.

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

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels.

If it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

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

(continued)

BASES

ACTIONS (continued)

G.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. The 24 hour Completion Time is acceptable due to the fact that these Functions are either not assumed in any accident or transient analysis in the FSAR (Manual Initiation) or, in the case of the TIP System isolation, the TIP System penetration is a small bore (0.280 inch), its isolation in a design basis event (with loss of offsite power) would be via the manually operated shear valves, and the ability to manually isolate by either the normal isolation valve or the shear valve is unaffected by the inoperable instrumentation. It should be noted, however, that the TIP System is powered from an auxiliary instrumentation bus which has an uninterruptible power supply and hence, the TIP drive mechanisms and ball valve control will still function in the event of a loss of offsite power. Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

H.1 and H.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, or any Required Action of Condition F or G is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

I.1 and I.2

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

(continued)

BASES

ACTIONS

I.1 and I.2 (continued

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

J.1 and J.2

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

SURVEILLANCE REQUIREMENTS

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

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 5 and 6) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary.

SR 3.3.6.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.1 (continued)

channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria which are determined by the plant staff based on an investigation of a combination of the channel instrument uncertainties may be used to support this parameter comparison and include indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit, and does not necessarily indicate the channel is Inoperable.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.6.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

The 92 day Frequency of SR 3.3.6.1.2 is based on the reliability analysis described in References 5 and 6.

This SR is modified by two Notes. Note 1 provides a general exception to the definition of CHANNEL FUNCTIONAL TEST. This exception is necessary because the design of instrumentation does not facilitate functional testing of all required contacts of the relays which input into the combinational logic. (Reference 11) Performance of such a test could result in a plant transient or place the plant in an undo risk situation. Therefore, for this SR, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of the relay which inputs into the combinational logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.2 (continued)

SYSTEM FUNCTIONAL TEST, SR 3.3.6.1.5. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

Note 2 provides a second specific exception to the definition of CHANNEL FUNCTIONAL TEST. For Functions 2.e, 3.a, and 4.a, certain channel relays are not included in the performance of the CHANNEL FUNCTIONAL TEST. These exceptions are necessary because the circuit design does not facilitate functional testing of the entire channel through to the coil of the relay which enters the combinational logic. (Reference 11) Specifically, testing of all required relays would require rendering the affected system (i.e., HPCI or RCIC) inoperable, or require lifting of leads and inserting test equipment which could lead to unplanned transients. Therefore, for these circuits, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the actuation of circuit devices up to the point where further testing could result in an unplanned transient. (References 10 and 12) The required relays not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.6.1.5. This exception is acceptable because operating experience shows that the devices not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

SR 3.3.6.1.3 and SR 3.3.6.1.4

A CHANNEL CALIBRATION verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.6.1.3 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.6.1.4 is based on the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.3 and SR 3.3.6.1.4 (continued)

It should be noted that some of the Primary Containment High Drywell pressure instruments, although only required to be calibrated as a 24 month Frequency, are calibrated quarterly based on the TS requirements.

SR 3.3.6.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety function. The 24 month Frequency is based on the need to perform portions of this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.6.1.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the guidance given in Reference 9 could not be met, which identified that degradation of response time can usually be detected by other surveillance tests.

As stated in Note 1, the response time of the sensors for Function 1.b is excluded from ISOLATION SYSTEM RESPONSE TIME testing. Because the vendor does not provide a design instrument response time, a penalty value to account for the sensor response time is included in determining total channel response time. The penalty value is based on the historical performance of the sensor. (Reference 13) This allowance is supported by Reference 9 which determined that significant degradation of the sensor channel response time can be detected during performance of other Technical Specification SRs and that the sensor response time is a small part of the overall ISOLATION RESPONSE TIME testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.6 (continued)

Function 1.a and 1.c channel sensors and logic components are excluded from response time testing in accordance with the provisions of References 14 and 15.

As stated in Note 2, response time testing of isolating relays is not required for Function 5.a. This allowance is supported by Reference 9. These relays isolate their respective isolation valve after a nominal 45 second time delay in the circuitry. No penalty value is included in the response time calculation of this function. This is due to the historical response time testing results of relays of the same manufacturer and model number being less than 100 milliseconds, which is well within the expected accuracy of the 45 second time delay relay.

ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in Reference 7. This test may be performed in one measurement, or in overlapping segments, with verification that all components are tested.

ISOLATION SYSTEM RESPONSE TIME tests are conducted on an 24 month STAGGERED TEST BASIS. The 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

REFERENCES

1. FSAR, Section 6.3.

2. FSAR, Chapter 15.

3. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.

4. FSAR, Section 4.2.3.4.3.

5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.

(continued)

BASES

REFERENCES (continued)

6. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

7. FSAR, Table 7.3-29.

8. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132)

9. NEDO-32291P-A "System Analyses for Elimination of Selected Response Time Testing Requirements," October 1995.

10. PPL Letter to NRC, PLA-2618, Response to NRC INSPECTION REPORTS 50-387/85-28 AND 50-388/85-23, dated April 22, 1986.

11. NRC Inspection and Enforcement Manual, Part 9900: Technical Guidance, Standard Technical Specification Section 1.0 Definitions, Issue date 12/08/86.

12. Susquehanna Steam Electric Station NRC REGION I COMBINED INSPECTION 50-387/90-20; 50-388/90-20, File R41-2, dated March 5, 1986.

13. NRC Safety Evaluation Report related to Amendment No. 171 for License No. NPF-14 and Amendment No. 144 for License No. NPF-22.

14. NEDO 32291-A, Supplement 1 "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1999.

15. NEDO 32291, Supplement 1, Addendum 2, "System Analyses for the Elimination of Selected Response Time Testing Requirements," September 5, 2003.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Loss of Coolant Accident confine the postulated release of radioactive material. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment.

The isolation devices for the penetrations in the primary containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. The primary containment air lock is OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Lock"; and

c. All equipment hatches are closed.

Several instruments connect to the primary containment atmosphere and are considered extensions of the primary containment. The leak rate tested instrument isolation valves identified in the Leakage Rate Test Program should be used as the primary containment boundary when the instruments are isolated and/or vented. Table B 3.6.1.1-1 contains the listing of the instruments and isolation valves.

(continued)

BACKGROUND (continued)

The H_2O_2 Analyzer lines beyond the PCIVs, up to and including the components within the H_2O_2 Analyzer panels, are extensions of primary containment (i.e., closed system), and are required to be leak rate tested in accordance with the Leakage Rate Test Program. The H_2O_2 Analyzer closed system boundary is identified in the Leakage Rate Test Program, and consists of components, piping, tubing, fittings, and valves, which meet the design guidance of Reference 7. Within the H_2O_2 Analyzer panels, the boundary ends at the first normally closed valve. The closed system boundary between PASS and the H_2O_2 Analyzer system ends at the Seismic Category I boundary between the two systems. This boundary occurs at the process sampling solenoid operated isolation valves (SV-22361, SV-22365, SV-22366, SV-22368, and SV-22369). These solenoid operated isolation valves do not fully meet the guidance of Reference 7 for closed system boundary valves in that they are not powered from a Class 1E power source. Based upon a risk determination, operating these valves as closed system boundary valves is not risk significant. These normally closed valves are required to be leakage rate tested in accordance with the Leakage Rate Test Program, since they form part of the closed system boundary for the H_2O_2 Analyzers. These valves are Aclosed system boundary valves@ and may be opened under administrative control, as delineated in Technical Requirements Manual (TRM) Bases 3.6.4. Opening of these valves to permit testing of PASS in Modes 1, 2, and 3 is permitted in accordance with TRO 3.6.4.

When the H_2O_2 Analyzer panels are isolated and/or vented, the panel isolation valves identified in the Leakage Rate Test Program should be used as the boundary of the extension of primary containment. Table B 3.6.1.1-2 contains a listing of the affected H_2O_2 Analyzer penetrations and panel isolation valves.

This Specification ensures that the performance of the primary containment, in the event of a Design Basis Accident (DBA), meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B and supporting documents (Ref. 3, 4 and 5), as modified by approved exemptions.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite and control room doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 1.0% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 48.6 psig.

Primary containment satisfies Criterion 3 of the NRC Policy Statement. (Ref. 6)

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to each startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

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

Leakage requirements for MSIVs and Secondary containment bypass are addressed in LCO 3.6.1.3.

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

ACTIONS

A.1

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

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. The primary containment concrete visual examinations may be performed during either power operation, e.g., performed concurrently with other primary containment inspection-related activities, or during a maintenance or refuel outage.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1 (continued)

The visual examinations of the steel liner plate inside primary containment are performed during maintenance or refueling outages since this is the only time the liner plate is fully accessible.

Failure to meet air lock leakage testing (SR 3.6.1.2.1) or resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.6) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. As left leakage prior to each startup after performing a required leakage test is required to be < 0.6 L_a for combined Type B and C leakage, and ≤ 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite and control room dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

SR Frequencies are as required by the Primary Containment Leakage Rate Testing Program. These periodic testing requirements verify that the primary containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

As noted in Table B 3.6.1.3-1, an exemption to Appendix J is provided that isolation barriers which remain filled or a water seal remains in the line post-LOCA are tested with water and the leakage is not included in the Type B and C 0.60 L_a test.

SR 3.6.1.1.2

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.2 (continued)

The allowable limit is 10% of the acceptable SSES $A/\sqrt{k}$ design value. For SSES, the $A/\sqrt{k}$ design value is .0535 ft^2.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the suppression chamber and determining the leakage. The leakage test is performed when the 10 CFR 50, Appendix J, Type A test is performed in accordance with the Primary Containment Leakage Rate Testing Program. This testing Frequency was developed considering this test is performed in conjunction with the Integrated Leak rate test and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs. Two consecutive test failures, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 24 months is required until the situation is remedied as evidenced by passing two consecutive tests.

SR 3.6.1.1.3

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through downcomers into the suppression pool. This SR measures suppression chamber-to-drywell vacuum breaker leakage to ensure the leakage paths that would bypass the suppression pool are within allowable limits. The total allowable leakage limit is 30% of the SR 3.6.1.1.2 limit. The allowable leakage per set is 12% of the SR 3.6.1.1.2 limit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.3 (continued)

The leakage is determined by establishing a 4.3 psi differential pressure across the drywell-to-suppression chamber vacuum breakers and verifying the leakage. The leakage test is performed every 24 months. The 24 month Frequency was developed considering the surveillance must be performed during a unit outage. A Note is provided which allows this Surveillance not to be performed when SR 3.6.1.1.2 is performed. This is acceptable because SR 3.6.1.1.2 ensures the OPERABILITY of the pressure suppression function including the suppression chamber-to-drywell vacuum breakers.

REFERENCES

1. FSAR, Section 6.2.
2. FSAR, Section 15.
3. 10 CFR 50, Appendix J, Option B.
4. Nuclear Energy Institute, 94-01.
5. ANSI/ANS 56.8-1994.
6. Final Policy Statement on Technical Specifications Improvements July 22, 1993 (58 FR 39132).
7. Standard Review Plan 6.2.4, Rev. 1, September 1975.

TABLE B 3.6.1.1-1

INSTRUMENT ISOLATION VALVES
(Page 1 of 2)

PENETRATION NUMBER	INSTRUMENT	INSTRUMENT ISOLATION VALVE
X-3B	PSH-C72-2N002A	IC-PSH-2N002A
	PSH L C72-2N004	IC-PSHL-2N004
	PS-E11-2N010A	IC-PS-2N010A
	PS-E11-2N011A	IC-PS-2N011A
	PSH-C72-2N002B	IC-PSH-2N002B
	PS-E11-2N010C	IC-PS-2N010C
	PS-E11-2N011C	IC-PS-2N011C
	PSH-25120C	IC-PSH-25120C
X-32A	PSH-C72-2N002D	IC-PSH-2N002D
	PS-E11-2N010B	IC-PS-2N010B
	PS-E11-2N011B	IC-PS-2N011B
	PSH-C72-2N002C	IC-PSH-2N002C
	PS-E11-2N010D	IC-PS-2N010D
	PS-E11-2N011D	IC-PS-2N011D
	PSH-25120D	IC-PSH-25120D
X-39A	FT-25120A	IC-FT-25120A HIGH and IC-FT-25120A LOW
X-39B	FT-25120B	IC-FT-25120B HIGH and IC-FT-25120B LOW
X-90A	PT-25709A	IC-PT-25709A
	PT-25710A	IC-PT-25710A
	PT-25728A1	IC-PT-25728A1
X-90D	PT-25709B	IC-PT-25709B
	PT-25710B	IC-PT-25710B
	PT-25728A	IC-PT-25728A

TABLE B 3.6.1.1-1

INSTRUMENT ISOLATION VALVES
(Page 2 of 2)

PENETRATION NUMBER	INSTRUMENT	INSTRUMENT ISOLATION VALVE
X-204A/205A	FT-25121A	IC-FT-25121A HIGH and IC-FT-25121A LOW
X-204B/205B	FT-25121B	IC-FT-25121A HIGH and IC-FT-25121A LOW
X-219A	LT-25775A	IC-LT-25775A REF and IC-LT-25775A VAR
	LSH-E41-2N015A	255027 and 255031
	LSH-E41-2N015B	255029 and 255033
X-223A	PT-25702	IC-PT-25702
X-232A	LT-25776A	IC-LT-25776A REF and IC-LT-25776A VAR
	PT-25729A	IC-PT-25729A
X234A	LT-25775B	IC-LT-25775B REF and IC-LT-25775B VAR
X-235A	LT-25776B	IC-LT-25776B REF and IC-LT-25776B VAR
	PT-25729B	IC-PT-25729B
	LI-25776B2	IC-LT-25776B2 REF and IC-LT-25776B2 VAR

TABLE B 3.6.1.1-2

H_2O_2 ANALYZER PANEL ISOLATION VALVES

PENETRATION NUMBER	PANEL ISOLATION VALVE[a]
X-60A, X-88B, X-221A, X-238A	257138 257139 257140 257141 257142
X-80C, X-221B, X-238B	257149 257150 257151 257152 257153

(a) Only those valves listed in this table with current leak rate test results, as identified in the Leakage Rate Test Program, may be used as isolation valves.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Lock

BASES

BACKGROUND

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

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

The air lock is an 8 ft 7 inch inside diameter cylindrical pressure vessel with doors at each end that are interlocked to prevent simultaneous opening. During periods when primary containment is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent primary containment entry is necessary. Under some conditions as allowed by this LCO, the primary containment may be accessed through the air lock, when the interlock mechanism has failed, by manually performing the interlock function.

The primary containment air lock forms part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.0% by weight of the containment air per 24 hours at the calculated maximum peak containment pressure (P_a) of 48.6 psig (Ref. 3). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

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

The primary containment air lock satisfies Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

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

The primary containment air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry or exit from primary containment.

(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, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the 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 is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

The ACTIONS are modified by a second Note, which ensures appropriate remedial measures are taken when necessary. This is an exception to LCO 3.0.6 which would not require action, even if primary containment is exceeding its leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment," to be taken in this event.

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

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

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour

(continued)

BASES

ACTIONS

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

Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door is being maintained closed.

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

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls. This 7 day limit is an accumulated limit that applies to the total combined time for all entries and exits. Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside primary containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an

(continued)

BASES

ACTIONS

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

allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

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

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

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

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

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

If the air lock is inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in an air lock have failed a seal

(continued)

BASES

ACTIONS

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

test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

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

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

D.1 and D.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

criteria were established based on engineering judgement and industry operating experience. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The SR has been modified by two Notes, Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 requires the results of airlock leakage tests be evaluated against the acceptance criteria of the Primary Containment Leakage Testing Program, 5.5.12. This ensures that the airlock leakage is properly accounted for in determining the combined Type B and C primary containment leakage.

SR 3.6.1.2.2

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.2 (continued)

performed with the reactor at power. The 24 month frequency for the interlock is justified based on generic operating experience. The 24 month frequency is based on engineering judgment and is considered adequate given the interlock is not challenged during the use of the airlock.

REFERENCES

1. FSAR, Section 3.8.2.1.2.

2. 10 CFR 50, Appendix J, Option B.

3. FSAR, Section 6.2.

4. Final Policy Statement on Technical Specifications Improvements July 22, 1993 (58 FR 39132).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

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

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that primary containment function assumed in the safety analyses will be maintained. For PCIVs, the primary containment isolation function is that the valve must be able to close (automatically or manually) and/or remain closed, and maintain leakage within that assumed in the DBA LOCA Dose Analysis. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. The OPERABILITY requirements for closed systems are discussed in Technical Requirements Manual (TRM) Bases 3.6.4. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system.

For each division of H_2O_2 Analyzers, the lines, up to and including the first normally closed valves within the H_2O_2

(continued)

BACKGROUND (continued)

Analyzer panels, are extensions of primary containment (i.e., closed system), and are required to be leak rate tested in accordance with the Leakage Rate Test Program. The H_2O_2 Analyzer closed system boundary is identified in the Leakage Rate Test Program. The closed system boundary consists of those components, piping, tubing, fittings, and valves, which meet the guidance of Reference 6. The closed system provides a secondary barrier in the event of a single failure of the PCIVs, as described below. The closed system boundary between PASS and the H_2O_2 Analyzer system ends at the process sampling solenoid operated isolation valves between the systems (SV-22361, SV-22365, SV-22366, SV-22368, and SV-22369). These solenoid operated isolation valves do not fully meet the guidance of Reference 6 for closed system boundary valves in that they are not powered from a Class 1E power source. However, based upon a risk determination, operating these valves as closed system boundary valves is not risk significant. These valves also form the end of the Seismic Category I boundary between the systems. These process sampling solenoid operated isolation valves are normally closed and are required to be leak rate tested in accordance with the Leakage Rate Test Program as part of the closed system for the H_2O_2 Analyzer system. These valves are "closed system boundary valves" and may be opened under administrative control, as delineated in Technical Requirements Manual (TRM) Bases 3.6.4. Opening of these valves to permit testing of PASS in Modes 1, 2, and 3 is permitted in accordance with TRO 3.6.4.

Each H_2O_2 Analyzer Sampling line penetrating primary containment has two PCIVs, located just outside primary containment. While two PCIVs are provided on each line, a single active failure of a relay in the control circuitry for these valves, could result in both valves failing to close or failing to remain closed. Furthermore, a single failure (a hot short in the common raceway to all the valves) could simultaneously affect all of the PCIVs within a H_2O_2 Analyzer division. Therefore, the containment isolation barriers for these penetrations consist of two PCIVs and a closed system. For situations where one or both PCIVs are inoperable, the ACTIONS to be taken are similar to the ACTIONS for a single PCIV backed by a closed system.

(continued)

BACKGROUND (continued)

The drywell vent and purge lines are 24 inches in diameter; the suppression chamber vent and purge lines are 18 inches in diameter. The containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. The outboard isolation valves have 2 inch bypass lines around them for use during normal reactor operation.

The RHR Shutdown Cooling return line containment penetrations {X-13A(B)}are provided with a normally closed gate valve {HV-251F015A(B)} and a normally open globe valve {HV-251F017A(B)} outside containment and a testable check valve {HV-251F050A(B)} with a normally closed parallel air operated globe valve {HV-251F122A(B)} inside containment. The gate valve is manually opened and automatically isolates upon a containment isolation signal from the Nuclear Steam Supply Shutoff System or RPV low level 3 when the RHR System is operated in the Shutdown Cooling Mode only. The LPCI subsystem is an operational mode of the RHR System and uses the same injection lines to the RPV as the Shutdown Cooling Mode.

The design of these containment penetrations is unique in that some valves are containment isolation valves while others perform the function of pressure isolation valves. In order to meet the 10 CFR 50 Appendix J leakage testing requirements, the HV-251F015A(B) and the closed system outside containment are the only barriers tested in accordance with the Leakage Rate Test Program. Since these containment penetrations {X-13A and X-13B} include a containment isolation valve outside containment that is tested in accordance with 10 CFR 50 Appendix J requirements and a closed system outside containment that meets the requirements of USNRC Standard Review Plan 6.2.4 (September 1975), paragraph II.3.e, the containment isolation provisions for these penetrations provide an acceptable alternative to the explicit requirements of 10 CFR 50, Appendix A, GDC 55.

Containment penetrations X-13A(B) are also high/low pressure system interfaces. In order to meet the requirements to have two (2) isolation valves between the high pressure and low pressure systems, the HV-251F050A(B), HV-251F122A(B), and HV-251F015A(B) valves are used to meet this requirement and are tested in accordance with the pressure test program.

(continued)

APPLICABLE SAFETY ANALYSES

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

The DBAs that result in a release of radioactive material within primary containment are a LOCA and a main steam line break (MSLB). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or close within the required isolation times following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. The closure time of the main steam isolation valves (MSIVs) for a MSLB outside primary containment is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the 5 second closure time is assumed in the analysis. The safety analyses assume that the purge valves were closed at event initiation. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The DBA analysis assumes that within the required isolation time leakage is terminated, except for the maximum allowable leakage rate, L_a.

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

The primary containment purge valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain closed during MODES 1, 2, and 3 except as permitted under Note 2 of SR 3.6.1.3.1. In this case, the single failure criterion remains applicable to the primary containment purge valve

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APPLICABLE SAFETY ANALYSIS (continued)

due to failure in the control circuit associated with each valve. The primary containment purge valve design precludes a single failure from compromising the primary containment boundary as long as the system is operated in accordance with this LCO.

Both H_2O_2 Analyzer PCIVs may not be able to close given a single failure in the control circuitry of the valves. The single failure is caused by a "hot short" in the cables/raceway to the PCIVs that causes both PCIVs for a given penetration to remain open or to open when required to be closed. This failure is required to be considered in accordance with IEEE-279 as discussed in FSAR Section 7.3.2a. However, the single failure criterion for containment isolation of the H_2O_2 Analyzer penetrations is satisfied by virtue of the combination of the associated PCIVs and the closed system formed by the H_2O_2 Analyzer piping system as discussed in the BACKGROUND section above.

The closed system boundary between PASS and the H_2O_2 Analyzer system ends at the process sampling solenoid operated isolation valves between the systems (SV-22361, SV-22365, SV-22366, SV-22368, and SV-22369). The closed system is not fully qualified to the guidance of Reference 6 in that the closed system boundary valves between the H_2O_2 system and PASS are not powered from a Class 1E power source. However, based upon a risk determination, the use of these valves is considered to have no risk significance. This exemption to the requirement of Reference 6 for the closed system boundary is documented in License Amendment No. 170.

PCIVs satisfy Criterion 3 of the NRC Policy Statement. (Ref. 2)

LCO

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

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an

(continued)

BASES

LCO (continued)

automatic isolation signal. The valves covered by this LCO are listed in Table B 3.6.1.3-1.

The normally closed PCIVs are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic valves are in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Table B 3.6.1.3-1.

Purge valves with resilient seals, secondary containment bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

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

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

(continued)

BASES

APPLICABILITY (continued)

OPERABLE and the primary containment purge valves are not required to be closed in MODES 4 and 5. Certain valves, however, are required to be OPERABLE to prevent inadvertent reactor vessel draindown. These valves are those whose associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." (This does not include the valves that isolate the associated instrumentation.)

ACTIONS

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

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

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

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for purge valve leakage not within limit,

(continued)

ACTIONS

A.1 and A.2 (continued)

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

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs except for the H_2O_2 Analyzer penetrations. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions. For the H_2O_2 Analyzer penetrations, Condition D provides the appropriate Required Actions.

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

B.1

With one or more penetration flow paths with two PCIVs inoperable except for purge valve leakage not within limit, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs except for the H_2O_2 Analyzer penetrations. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions. For the H_2O_2 Analyzer penetrations, Condition D provides the appropriate Required Actions.

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to

(continued)

ACTIONS

C.1 and C.2 (continued)

OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within the 72 hour Completion Time. The Completion Time of 72 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The closed system must meet the requirements of Reference 6. For conditions where the PCIV and the closed system are inoperable, the Required Actions of TRO 3.6.4, Condition B apply. For the Excess Flow Check Valves (EFCV), the Completion Time of 12 hours is reasonable considering the instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs and the H_2O_2 Analyzer penetration, Conditions A, B, and D provide the appropriate Required Actions.

Required Action C.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically

(continued)

ACTIONS

C.1 and C.2 (continued)

restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

D.1 and D.2

With one or more H_2O_2 Analyzer penetrations with one or both PCIVs inoperable, the inoperable valve(s) must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action D.1 must be completed within the 72 hour Completion Time. The Completion Time of 72 hours is reasonable considering the unique design of the H_2O_2 Analyzer penetrations. The containment isolation barriers for these penetrations consist of two PCIVs and a closed system. In addition, the Completion Time of 72 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. In the event the affected penetration flow path is isolated in accordance with Required Action D.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

When an H_2O_2 Analyzer penetration PCIV is to be closed and deactivated in accordance with Condition D, this must be accomplished by pulling the fuse for the power supply, and either determinating the power cables at the solenoid valve, or jumpering of the power side of the solenoid to ground.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

The OPERABILITY requirements for the closed system are discussed in Technical Requirements Manual (TRM) Bases 3.6.4. In the event that either one or both of the PCIVs and the closed system are inoperable, the Required Actions of TRO 3.6.4, Condition B apply.

Condition D is modified by a Note indicating that this Condition is only applicable to the H_2O_2 Analyzer penetrations.

(continued)

ACTIONS
(continued)

E.1

With the secondary containment bypass leakage rate not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of secondary containment bypass leakage to the overall containment function.

F.1

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits. The 24 hour Completion Time is reasonable, considering that one containment purge valve remains closed, except as controlled by SR 3.6.1.3.1 so that a gross breach of containment does not exist.

G.1 and G.2

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

(continued)

BASES

ACTIONS (continued)

H.1 and H.2

If any Required Action and associated Completion Time cannot be met, the unit must be placed in a condition in which the LCO does not apply. 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 or valve(s) are restored to OPERABLE status. If suspending an OPDRV would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valve(s) to OPERABLE status. This allows RHR to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is also modified by Note 1, stating that primary containment purge valves are only required to be closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves, or the release of radioactive material will exceed limits prior to the purge valves closing. At other times when the purge valves are required to be capable of closing (e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are allowed to be open. The SR is modified by Note 2 stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The vent and purge valves are capable of closing in the environment following

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other PCIV requirements discussed in SR 3.6.1.3.2.

SR 3.6.1.3.2

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

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

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange that is located inside

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, the Frequency defined as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing. Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

SR 3.6.1.3.4

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

SR 3.6.1.3.5

Verifying the isolation time of each power operated and each automatic PCIV is within limits is required to demonstrate

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.5 (continued)

OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.7. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the Final Safety Analyses Report. The isolation time and Frequency of this SR are in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.6

For primary containment purge valves with resilient seals, the Appendix J Leakage Rate Test Interval of 24 months is sufficient. The acceptance criteria for these valves is defined in the Primary Containment Leakage Rate Testing Program, 5.5.12.

The SR is modified by a Note stating that the primary containment purge valves are only required to meet leakage rate testing requirements in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, purge valve leakage must be minimized to ensure offsite radiological release is within limits. At other times when the purge valves are required to be capable of closing (e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are not required to meet any specific leakage criteria.

SR 3.6.1.3.7

Verifying that the isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. This ensures that the calculated radiological consequences of these events remain within regulatory limits.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.7

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

SR 3.6.1.3.8

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.5 overlaps this SR to provide complete testing of the safety function. The 24 month Frequency was developed considering it is prudent that some of these Surveillances be performed only during a unit outage since isolation of penetrations could eliminate cooling water flow and disrupt the normal operation of some critical components. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.9

This SR requires a demonstration that a representative sample of reactor instrumentation line excess flow check valves (EFCV) are OPERABLE by verifying that the valve actuates to check flow on a simulated instrument line break. As defined in FSAR Section 6.2.4.3.5 (Reference 4), the conditions under which an EFCV will isolate, simulated instrument line breaks are at flow rates which develop a differential pressure of between 3 psid and 10 psid. This SR provides assurance that the instrumentation line EFCVs will perform its design function to check flow. No specific valve leakage limits are specified because no specific leakage limits are defined in the FSAR. The 24 month Frequency is based on the need to perform some of these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The representative sample consists of an approximate equal number of EFCVs such that each EFCV is tested at least once every 10 years (nominal). The nominal 10 year interval is based on other performance-based testing programs, such as Inservice Testing (snubbers) and Option B to 10 CFR 50, Appendix J. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes and operating environments. This ensures that any potential common problem with a specific type or application of EFCV is

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.9 (continued)

detected at the earliest possible time. EFCV failures will be evaluated to determine if additional testing in that test interval is warranted to ensure overall reliability and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint (Reference 7).

SR 3.6.1.3.10

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

SR 3.6.1.3.11

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations of Reference 4 are met. The secondary containment leakage pathways and Frequency are defined by the Primary Containment Leakage Rate Testing Program. This SR simply imposes additional acceptance criteria. A note is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other MODES, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

SR 3.6.1.3.12

The analyses in References 1 and 4 are based on the specified leakage rate. Leakage through each MSIV must be $\leq$ 100 scfh for anyone MSIV and $\leq$ 300 scfh for total leakage through the MSIVs combined with the Main Steam Line Drain Isolation Valve, HPCI Steam Supply Isolation Valve and the RCIC Steam Supply Isolation Valve. The MSIVs can be tested at either $\geq$ Pt (24.3 psig) or P_a (48.6 psig). Main Steam Line Drain Isolation, HPCI and RCIC Steam Supply Line Isolation Valves, are tested at P_a (48.6 psig). A note is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.12 (continued)

conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.3.13

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 2 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is 3.3 gpm when tested at 1.1 P_a, (53.46 psig). The combined leakage rates must be demonstrated in accordance with the leakage rate test Frequency required by the Primary Containment Leakage Testing Program.

As noted in Table B 3.6.1.3-1, PCIVs associated with this SR are not Type C tested. Containment bypass leakage is prevented since the line terminates below the minimum water level in the suppression chamber. These valves are tested in accordance with the IST Program. Therefore, these valves leakage is not included as containment leakage.

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

REFERENCES

1. FSAR, Chapter 15.
2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
3. 10 CFR 50, Appendix J, Option B.
4. FSAR, Section 6.2.
5. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

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BASES

REFERENCES
(continued)

6. Standard Review Plan 6.2.4, Rev. 1, September 1975.

7. NEDO-32977-A, "Excess Flow Check Valve Testing Relaxation," June 2000.

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Containment Atmospheric Control	2-57-199 (d)	ILRT	Manual	N/A
	2-57-200 (d)	ILRT	Manual	N/A
	HV-25703	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25704	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25705	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25711	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25713	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25714	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25721	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25722	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25723	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25724	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25725	Containment Purge	Automatic Valve	2.b, 2.d, 2.e (15)
	HV-25766 (a)	Suppression Pool Cleanup	Automatic Valve	2.b, 2.d (35)
	HV-25768 (a)	Suppression Pool Cleanup	Automatic Valve	2.b, 2.d (30)
	SV-257100 A	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257100 B	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257101 A	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257101 B	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257102 A	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257102 B	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257103 A	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257103 B	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257104	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257105	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257106	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-257107	Containment Radiation Detection Syst	Automatic Valve	2.b, 2.d, 2.f
	SV-25734 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25734 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25736 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25736 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25737	Nitrogen Makeup	Automatic Valve	2.b, 2.d, 2.e

Table B 3.6.1.3-1
Primary Containment Isolation Valve
(Page 2 of 10)

Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Containment Atmospheric Control (continued)	SV-25738	Nitrogen Makeup	Automatic Valve	2.b, 2.d, 2.e
	SV-25740 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25740 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25742 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25742 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25750 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25750 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25752 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25752 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25767	Nitrogen Makeup	Automatic Valve	2.b, 2.d, 2.e
	SV-25774 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25774 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25776 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25776 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25780 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25780 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25782 A (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25782 B (e)	Containment Atmosphere Sample	Automatic Valve	2.b, 2.d
	SV-25789	Nitrogen Makeup	Automatic Valve	2.b, 2.d, 2.e
Containment Instrument Gas	2-26-072 (d)	Containment Instrument Gas	Manual Check	N/A
	2-26-074 (d)	Containment Instrument Gas	Manual Check	N/A
	2-26-152 (d)	Containment Instrument Gas	Manual Check	N/A
	2-26-154 (d)	Containment Instrument Gas	Manual Check	N/A
	2-26-164 (d)	Containment Instrument Gas	Manual Check	N/A
	HV-22603	Containment Instrument Gas	Automatic Valve	2.c, 2.d (20)
	SV-22605	Containment Instrument Gas	Automatic Valve	2.c, 2.d
	SV-22651	Containment Instrument Gas	Automatic Valve	2.c, 2.d
	SV-22654 A	Containment Instrument Gas	Power Operated	N/A
	SV-22654 B	Containment Instrument Gas	Power Operated	N/A
	SV-22661	Containment Instrument Gas	Automatic Valve	2.b, 2.d
	SV-22671	Containment Instrument Gas	Automatic Valve	2.b, 2.d
Core Spray	HV-252F001 A (b)(c)	CS Suction	Power Operated	N/A
	HV-252F001 B (b)(c)	CS Suction	Power Operated	N/A
	HV-252F005 A	CS Injection	Power Operated	N/A
	HV-252F005 B	CS Injection	Power Operated	N/A
	HV-252F006 A	CS Injection	Air Operated Check Valve	N/A
	HV-252F006 B	CS Injection	Air Operated Check Valve	N/A
	HV-252F015 A (b)(c)	CS Test	Automatic Valve	2.c, 2.d (80)
	HV-252F015 B (b)(c)	CS Test	Automatic Valve	2.c, 2.d (80)
	HV-252F031 A (b)(c)	CS Minimum Recirculation Flow	Power Operated	N/A
	HV-252F031 B (b)(c)	CS Minimum Recirculation Flow	Power Operated	N/A

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Core Spray (continued)	HV-252F037 A	CS Injection	Power Operated (Air)	N/A
	HV-252F037 B	CS Injection	Power Operated (Air)	N/A
	XV-252F018 A	Core Spray	Excess Flow Check Valve	N/A
	XV-252F018 B	Core Spray	Excess Flow Check Valve	N/A
Demin Water	2-41-017 (d)	Demineralized Water	Manual	N/A
	2-41-018 (d)	Demineralized Water	Manual	N/A
HPCI	2-55-038 (d)	HPCI Injection	Manual	N/A
	255F046 (b) (c) (d)	HPCI Minimum Recirculation Flow	Manual Check	N/A
	255F049 (a) (d)	HPCI	Manual Check	N/A
	HV-255F002	HPCI Steam Supply	Automatic Valve	3.a, 3.b, 3.c, 3.e, 3.f, 3.g, (50)
	HV-255F003	HPCI Steam Supply	Automatic Valve	3.a, 3.b, 3.c, 3.e, 3.f, 3.g, (50)
	HV-255F006	HPCI Injection	Power Operated	N/A
	HV-255F012 (b) (c)	HPCI Minimum Recirculation Flow	Power Operated	N/A
	HV-255F042 (b) (c)	HPCI Suction	Automatic Valve	3.a, 3.b, 3.c, 3.e, 3.f, 3.g, (90)
	HV-255F066 (a)	HPCI Turbine Exhaust	Power Operated	N/A
	HV-255F075	HPCI Vacuum Breaker	Automatic Valve	3.b, 3.d, (15)
	HV-255F079	HPCI Vacuum Breaker	Automatic Valve	3.b, 3.d, (15)
	HV-255F100	HPCI Steam Supply	Automatic Valve	3.a, 3.b, 3.c, 3.e, 3.f, 3.g, (6)
	XV-255F024 A	HPCI	Excess Flow Check Valve	N/A
	XV-255F024 B	HPCI	Excess Flow Check Valve	N/A
	XV-255F024 C	HPCI	Excess Flow Check Valve	N/A
	XV-255F024 D	HPCI	Excess Flow Check Valve	N/A
Liquid Radwaste Collection	HV-26108 A1	Liquid Radwaste	Automatic Valve	2.b, 2.d (15)
	HV-26108 A2	Liquid Radwaste	Automatic Valve	2.b, 2.d (15)
	HV-26116 A1	Liquid Radwaste	Automatic Valve	2.b, 2.d (15)
	HV-26116 A2	Liquid Radwaste	Automatic Valve	2.b, 2.d (15)
Nuclear Boiler	241F010 A (d)	Feedwater	Manual Check	N/A
	241F010 B (d)	Feedwater	Manual Check	N/A
	241F039 A (d)	Feedwater Isolation Valve	Manual Check	N/A
	241F039 B (d)	Feedwater Isolation Valve	Manual Check	N/A
	241818 A (d)	Feedwater Isolation Valve	Manual Check	N/A
	241818 B (d)	Feedwater Isolation Valve	Manual Check	N/A

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Nuclear Boiler (continued)	HV-241F016	MSL Drain	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (10)
	HV-241F019	MSL Drain	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (15)
	HV-241F022 A	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F022 B	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F022 C	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F022 D	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F028 A	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F028 B	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F028 C	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F028 D	MSIV	Automatic Valve	1.a, 1.b, 1.c, 1.d, 1.e (5)
	HV-241F032 A	Feedwater Isolation Valve	Power Operated Check Valves	N/A
	HV-241F032 B	Feedwater Isolation Valve	Power Operated Check Valves	N/A
	XV-241F009	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F070 A	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F070 B	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F070 C	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F070 D	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F071 A	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F071 B	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F071 C	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F071 D	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F072 A	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F072 B	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F072 C	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F072 D	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F073 A	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Nuclear Boiler (continued)	XV-241F073 B	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F073 C	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
	XV-241F073 D	Nuclear Boiler EFCV	Excess Flow Check Valve	N/A
Nuclear Boiler Vessel Instrumentation	XV-24201	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-24202	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F041	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F043 A	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F043 B	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F045 A	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F045 B	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F047 A	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F047B	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F051 A	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F051 B	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F051 C	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F051 D	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F053 A	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F053 B	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F053 C	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F053 D	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F055	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F057	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 A	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 B	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A

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Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Nuclear Boiler Vessel Instrumentation (continued)	XV-242F059 C	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 D	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 E	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 F	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 G	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 H	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 L	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 M	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 N	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 P	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 R	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 S	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 T	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F059 U	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
	XV-242F061	Nuclear Boiler Vessel Instrument	Excess Flow Check Valve	N/A
RB Chilled Water System	HV-28781 A1	RB Chilled Water	Automatic Valve	2.c, 2.d (40)
	HV-28781 A2	RB Chilled Water	Automatic Valve	2.c, 2.d (40)
	HV-28781 B1	RB Chilled Water	Automatic Valve	2.c, 2.d (40)
	HV-28781 B2	RB Chilled Water	Automatic Valve	2.c, 2.d (40)
	HV-28782 A1	RB Chilled Water	Automatic Valve	2.c, 2.d (12)
	HV-28782 A2	RB Chilled Water	Automatic Valve	2.c, 2.d (12)
	HV-28782 B1	RB Chilled Water	Automatic Valve	2.c, 2.d (12)
	HV-28782 B2	RB Chilled Water	Automatic Valve	2.c, 2.d (12)
	HV-28791 A1	RB Chilled Water	Automatic Valve	2.b, 2.d (15)
	HV-28791 A2	RB Chilled Water	Automatic Valve	2.b, 2.d (15)
	HV-28791 B1	RB Chilled Water	Automatic Valve	2.b, 2.d (15)
	HV-28791 B2	RB Chilled Water	Automatic Valve	2.b, 2.d (15)
	HV-28792 A1	RB Chilled Water	Automatic Valve	2.b, 2.d (8)
	HV-28792 A2	RB Chilled Water	Automatic Valve	2.b, 2.d (8)
	HV-28792 B1	RB Chilled Water	Automatic Valve	2.b, 2.d (8)

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
RB Chilled Water System (continued)	HV-28792 B2	RB Chilled Water	Automatic Valve	2.b, 2.d (8)
RBCCW	HV-21313	RBCCW	Automatic Valve	2.c, 2.d (30)
	HV-21314	RBCCW	Automatic Valve	2.c, 2.d (30)
	HV-21345	RBCCW	Automatic Valve	2.c, 2.d (30)
	HV-21346	RBCCW	Automatic Valve	2.c, 2.d (30)
RCIC	2-49-020 (d)	RCIC Injection	Manual	N/A
	249F021 (b) (c) (d)	RCIC Minimum Recirculation Flow	Manual Check	N/A
	249F028 (a) (d)	RCIC Vacuum Pump Discharge	Manual	N/A
	249F040 (a) (d)	RCIC Turbine Exhaust	Manual	N/A
	FV-249F019 (b) (c)	RCIC Minimum Recirculation Flow	Power Operated	N/A
	HV-249F007	RCIC Steam Supply	Automatic Valve	4.a, 4.b, 4.c, 4.e, 4.f, 4.g (20)
	HV-249F008	RCIC Steam Supply	Automatic Valve	4.a, 4.b, 4.c, 4.e, 4.f, 4.g (20)
	HV-249F013	RCIC Injection	Power Operated	N/A
	HV-249F031 (b) (c)	RCIC Suction	Power Operated	N/A
	HV-249F059 (a)	RCIC Turbine Exhaust	Power Operated	N/A
	HV-249F060 (a)	RCIC Vacuum Pump Discharge	Power Operated	N/A
	HV-249F062	RCIC Vacuum Breaker	Automatic Valve	4.b, 4.d (10)
	HV-249F084	RCIC Vacuum Breaker	Automatic Valve	4.b, 4.d (10)
	HV-249F088	RCIC Steam Supply	Automatic Valve	4.a, 4.b, 4.c, 4.e, 4.f, 4.g (12)
	XV-249F044 A	RCIC	Excess Flow Check Valve	N/A
	XV-249F044 B	RCIC	Excess Flow Check Valve	N/A
	XV-249F044 C	RCIC	Excess Flow Check Valve	N/A
	XV-249F044 D	RCIC	Excess Flow Check Valve	N/A
Reactor Recirculation	243F013 A (d)	Recirculation Pump Seal Water	Manual Check	N/A
	243F013 B (d)	Recirculation Pump Seal Water	Manual Check	N/A
	HV-243F019	Reactor Coolant Sample	Automatic Valve	2.b (9)
	HV-243F020	Reactor Coolant Sample	Automatic Valve	2.b (2)
	XV-243F003 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F003 B	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F004 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F004 B	Reactor Recirculation	Excess Flow Check Valve	N/A

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Reactor Recirculation (continued)	XV-243F009 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F009 B	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F009 C	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F009 D	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F010 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F010 B	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F010 C	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F010 D	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F011 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F011 B	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F011 C	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F011 D	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F012 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F012 B	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F012 C	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F012 D	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F017 A	Recirculation Pump Seal Water	Excess Flow Check Valve	N/A
	XV-243F017 B	Recirculation Pump Seal Water	Excess Flow Check Valve	N/A
	XV-243F040 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F040 B	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F040 C	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F040 D	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F057 A	Reactor Recirculation	Excess Flow Check Valve	N/A
	XV-243F057 B	Reactor Recirculation	Excess Flow Check Valve	N/A
Residual Heat Removal	HV-251F004 A (b) (c)	RHR – Suppression Pool Suction	Power Operated	N/A
	HV-251F004 B (b) (c)	RHR – Suppression Pool Suction	Power Operated	N/A
	HV-251F004 C (b) (c)	RHR – Suppression Pool Suction	Power Operated	N/A

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
Residual Heat Removal (continued)	HV-251F004 D(b) (c)	RHR – Suppression Pool Suction	Power Operated	N/A
	HV-251F007 A (b) (c)	RHR – Minimum Recirculation	Power Operated	N/A
	HV-251F007 B (b) (c)	RHR – Minimum Recirculation	Power Operated	N/A
	HV-251F008	RHR – Shutdown Cooling Suction	Automatic Valve	6.a, 6.b, 6.c (52)
	HV-251F009	RHR – Shutdown Cooling Suction	Automatic Valve	6.a, 6.b, 6.c (52)
	HV-251F011 A (b) (d)	RHR – Suppression Pool Cooling	Manual	N/A
	HV-251F011 B (b) (d)	RHR – Suppression Pool Cooling	Manual	N/A
	HV-251F015 A (f)	RHR – Shutdown Cooling Return/LPCI Injection	Power Operated	N/A
	HV-251F015 B (f)	RHR – Shutdown Cooling Return/LPCI Injection	Power Operated	N/A
	HV-251F016 A (b)	RHR – Drywell Spray	Automatic Valve	2.c, 2.d (90)
	HV-251F016 B (b)	RHR – Drywell Spray	Automatic Valve	2.c, 2.d (90)
	HV-251F022	RHR – Reactor Vessel Head Spray	Automatic Valve	2.d, 6.a, 6.b, 6.c (30)
	HV-251F023	RHR – Reactor Vessel Head Spray	Automatic Valve	2.d, 6.a, 6.b, 6.c (20)
	HV-251F028 A (b)	RHR – Suppression Pool Cooling/Spray	Automatic Valve	2.c, 2.d (90)
	HV-251F028 B (b)	RHR – Suppression Pool Cooling/Spray	Automatic Valve	2.c, 2.d (90)
	HV-251F050 A (g)	RHR – Shutdown Cooling Return/LPCI Injection	Air Operated Check Valve	N/A
	HV-251F050 B (g)	RHR – Shutdown Cooling Return/LPCI Injection	Air Operated Check Valve	N/A
	HV-251F103 A (b)	RHR Heat Exchanger Vent	Power Operated	N/A
	HV-251F103 B (b)	RHR Heat Exchanger Vent	Power Operated	N/A
	HV-251F122 A (g)	RHR – Shutdown Cooling Return/LPCI Injection	Power Operated (Air)	N/A
	HV-251F122 B (g)	RHR – Shutdown Cooling Return/LPCI Injection	Power Operated (Air)	N/A
	PSV-25106 A (b) (d)	RHR- Relief Valve Discharge	Relief Valve	N/A
	PSV-25106 B (b) (d)	RHR- Relief Valve Discharge	Relief Valve	N/A
	PSV-251F126 (d)	RHR- Shutdown Cooling Suction	Relief Valve	N/A
	XV-25109 A	RHR	Excess Flow Check Valve	N/A
	XV-25109 B	RHR	Excess Flow Check Valve	N/A
	XV-25109 C	RHR	Excess Flow Check Valve	N/A
	XV-25109 D	RHR	Excess Flow Check Valve	N/A
RWCU	HV-244F001 (a)	RWCU Suction	Automatic Valve	5.a, 5.b, 5.c, 5.d, 5.f, 5.g (30)
	HV-244F004 (a)	RWCU Suction	Automatic Valve	5.a, 5.b, 5.c, 5.d, 5.e, 5.f, 5.g (30)
	XV-24411 A	RWCU	Excess Flow Check Valve	N/A
	XV-24411 B	RWCU	Excess Flow Check Valve	N/A

Table B 3.6.1.3-1
Primary Containment Isolation Valve
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Plant System	Valve Number	Valve Description	Type of Valve	Isolation Signal LCO 3.3.6.1 Function No. (Maximum Isolation Time (Seconds))
RWCU (continued)	XV-24411 C	RWCU	Excess Flow Check Valve	N/A
	XV-24411 D	RWCU	Excess Flow Check Valve	N/A
	XV-244F046	RWCU	Excess Flow Check Valve	N/A
	HV-24182 A	RWCU Return	Power Operated	N/A
	HV-24182 B	RWCU Return	Power Operated	N/A
SLCS	248F007 (a) (d)	SLCS	Manual Check	N/A
	HV-248F006 (a)	SLCS	Power Operated Check Valve	N/A
TIP System	C51-J004 A (Ball Valve)	TIP Ball Valves	Automatic Valve	7.a, 7.b (5)
	C51-J004 B (Ball Valve)	TIP Ball Valves	Automatic Valve	7.a, 7.b (5)
	C51-J004 C (Ball Valve)	TIP Ball Valves	Automatic Valve	7.a, 7.b (5)
	C51-J004 D (Ball Valve)	TIP Ball Valves	Automatic Valve	7.a, 7.b (5)
	C51-J004 E (Ball Valve)	TIP Ball Valves	Automatic Valve	7.a, 7.b (5)
TIP System (continued)	C51-J004 A (Shear Valve)	TIP Shear Valves	Squib Valve	N/A
	C51-J004 B (Shear Valve)	TIP Shear Valves	Squib Valve	N/A
	C51-J004 C (Shear Valve)	TIP Shear Valves	Squib Valve	N/A
	C51-J004 D (Shear Valve)	TIP Shear Valves	Squib Valve	N/A
	C51-J004 E (Shear Valve)	TIP Shear Valves	Squib Valve	N/A

(a) Isolation barrier remains filled or a water seal remains in the line post-LOCA, isolation valve is tested with water. Isolation valve leakage is not included in 0.60 L_a total Type B and C tests.

(b) Redundant isolation boundary for this valve is provided by the closed system whose integrity is verified by the Leakage Rate Test Program. This footnote does not apply to valve 255F046 (HPCI) when the associated PCIV, HV255F012 is closed and deactivated. Similarly, this footnote does not apply to valve 249F021 (RCIC) when its associated PCIV, FV249F019 is closed and deactivated.

(c) Containment Isolation Valves are not Type C tested. Containment bypass leakage is prevented since the line terminates below the minimum water level in the Suppression Chamber. Refer to the IST Program.

(d) LCO 3.3.3.1, "PAM Instrumentation," Table 3.3.3.1-1, Function 6, (PCIV Position) does not apply since these are relief valves, check valves, manual valves or deactivated and closed.

(e) The containment isolation barriers for the penetration associated with this valve consists of two PCIVs and a closed system. The closed system provides a redundant isolation boundary for both PCIVs, and its integrity is required to be verified by the Leakage Rate Test Program.

(f) Redundant isolation boundary for this valve is provided by the closed system whose integrity is verified by the Leakage Rate Test Program.

(g) These valves are not required to be 10 CFR 50, Appendix J tested since the HV-251F015A(B) valves and a closed system form the 10 CFR 50, Appendix J boundary. These valves form a high/low pressure interface and are pressure tested in accordance with the pressure test program.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Containment Pressure

BASES

BACKGROUND

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

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial containment pressure of -1.0 to 2.0 psig. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA containment internal pressure does not exceed the maximum allowable.

The maximum calculated containment pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak containment pressure for this limiting event is 48.6 psig (Ref. 1).

The minimum containment pressure occurs during an inadvertent spray actuation. The calculated minimum drywell pressure for this limiting event is -4.72 psig. (Ref. 1)

Containment pressure satisfies Criterion 2 of the NRC Policy Statement. (Ref. 2)

LCO

In the event of a DBA, with an initial containment pressure -1.0 to 2.0 psig, the resultant peak containment accident pressure will be maintained below the containment design pressure. The containment pressure is defined to include both the drywell pressure and the suppression chamber pressure. (Ref. 1)

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within limits is not required in MODE 4 or 5.

ACTIONS

A.1

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

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

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

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 6.2.

2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).