JAMES A. FITZPATRICK NUCLEAR POWER PLANT
TECHNICAL SPECIFICATIONS BASES
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		B 3.10.4-5	30		
B 3.9.4-1	0				
B 3.9.4-2	0	B 3.10.5-1	0		
B 3.9.4-3	0	B 3.10.5-2	0		
B 3.9.4-4	0	B 3.10.5-3	0		
		B 3.10.5-4	30		
B 3.9.5-1	0				
B 3.9.5-2	30	B 3.10.6-1	0		
B 3.9.5-3	0	B 3.10.6-2	0		
		B 3.10.6-3	30		
B 3.9.6-1	0				
B 3.9.6-2	0	B 3.10.7-1	0		
B 3.9.6-3	30	B 3.10.7-2	0		
		B 3.10.7-3	0		
B 3.9.7-1	2	B 3.10.7-4	0		
B 3.9.7-2	0				
B 3.9.7-3	0	B 3.10.8-1	0		
B 3.9.7-4	30	B 3.10.8-2	0		
		B 3.10.8-3	0		
B 3.9.8-1	0	B 3.10.8-4	0		
B 3.9.8-2	0	B 3.10.8-5	30		
B 3.9.8-3	0	B 3.10.8-6	0		

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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

JAFNPP design criteria (Ref. 1) requires. and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and abnormal operational transients.

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. 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. This is accomplished by having a Safety Limit Minimum Critical Power Ratio (SLMCPR) design basis, refered to as SLMCPR (95/95), which corresponds to 95% probability at 95% confidence level (the 95/95 MCPR criterion) that transition boiling will not occur.

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

(continued)

BASES

BACKGROUND (continued)

to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSIS

The fuel cladding must not sustain damage as a result of normal operation and abnormal operational transients. The Technical Specification SL is set generically on a fuel product MCPR correlation basis as the MCPR which corresponds to 95% probability at a 95% confidence level that transition boiling will not occur, referred to as SLMCPR (95/95).

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 GEXL17 critical power correlation is applicable for all critical power calculations at pressure ≥ 685 psig and core flows ≥10% of rated flow (References 5 and 6). For operation at low pressures or low flows, another basis is used, as follows:

> Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be > 4.5 psi. Analyses (Ref. 2) show that with a bundle flow of 28 x 10^3 lb/hr. bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be > 28 x 10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER> 50% RTP. Thus, a THERMAL POWER limit of 25% RTP for reactor pressure < 785 psig (including the GEXL17 correlation lower limit of 685 psig) is conservative.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

2.1.1.2 MCPR

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit.

The Technical Specification SL value is dependent on the fuel product line and the corresponding MCPR correlation, which is cycle independent. The value is based on the Critical Power Ratio (CPR) data statistics and a 95% probability with 95% confidence that rods are not susceptible to boiling transition, referred to as MCPR (95/95).

The SL is based on GNF2 fuel. For cores loaded with a single fuel product line, the SLMCPR (95/95) is the MCPR (95/95) for the fuel type. For cores loaded with a mix of applicable fuel types, the SLMCPR (95/95) is based on the largest (i, e. most limiting) of the MCPR values for the fuel product lines that are fresh or once-burnt at the start of the cycle.

2.1.1.3 Reactor Vessel Water Level

The reactor vessel water level is required to be above the top of the active irradiated fuel. The top of the active irradiated fuel is the top of a 150 inch fuel column which includes both the enriched and the natural uranium. During MODES 1 and 2 the reactor vessel water level is required to be above the top of the active irradiated 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. 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.

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BASES (continued)

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to prevent 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 a SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). 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 UFSAR, Section 16.6.

2 NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, (Revision specified in the COLR).

3 Not Used

4 10 CFR 100.

5 NEDC-33292P, Rev 3, “GEXL17 Correlation for GNF2 Fuel”, dated June 2009.

6 NEDC-33270P, Rev. 7, “GNF2 Advantage Generic Compliance with NEDE-24011-P-A (GESTAR II)”, dated October 2016.

7 NRC Letter, Issuance of Amendment RE: Application to Revise Technical Specifications for Technical Specification Low Pressure Safety Limit (TAC No. MF2897), ML15014A277 dated February 9, 2015.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on reactor steam dome pressure protects the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. Establishing an upper limit on reactor steam dome pressure ensures continued RCS integrity. According to JAFNPP design criteria (Ref. 1), the reactor coolant pressure boundary (RCPB) shall be designed with sufficient margin to ensure that the design conditions are not exceeded during normal operation and abnormal operational transients.

During normal operation and abnormal operational transients, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, in accordance with ASME Code requirements, prior to initial operation when there is no fuel in the core. Any further hydrostatic testing with fuel in the core may be done under LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation." Following inception of unit operation, RCS components shall be pressure tested in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB, reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 4). If this occurred in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere.

APPLICABLE SAFETY ANALYSES

The RCS safety/relief valves and the Reactor Protection System Reactor Vessel Steam Dome Pressure-High Function have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressure SL has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME, Boiler and Pressure Vessel Code, 1965 Edition including Addenda through the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

winter of 1966 (Ref. 5), which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The SL of 1325 psig, as measured in the reactor steam dome, is equivalent to 1375 psig at the lowest elevation of the RCS. The RCS is designed to the USAS Nuclear Power Piping Code, Section B31.1.0, 1967 Edition, including Addendum A through 1969 (Ref. 6), for the reactor recirculation piping, which permits a maximum pressure transient of 120% of design pressures of 1148 psig for suction piping and 1274 psig for discharge piping. The RCS pressure SL is selected to be the lowest transient overpressure allowed by the applicable codes.

SAFETY LIMITS

The maximum transient pressure allowable in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RCS piping, valves, and fittings is 120% of design pressures of 1148 psig for suction piping and 1274 psig for discharge piping. The most limiting of these allowances is the 110% of the reactor pressure vessel design pressure; therefore, the SL on maximum allowable RCS pressure is established at 1325 psig as measured at the reactor steam dome.

APPLICABILITY

SL 2.1.2 applies in all MODES.

SAFETY LIMIT VIOLATIONS

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also assures that the probability of an accident occurring during this period is minimal.

REFERENCES

1. UFSAR, Section 16.6.

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.

3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWA-5000.

4. 10 CFR 100.

(continued)

BASES

REFERENCES (continued)

5. ASME, Boiler and Pressure Vessel Code, Section III, 1965 Edition, Addenda winter of 1966.

6. ASME, USAS, Nuclear Power Piping Code, Section B31.1.0, 1967 Edition, with Addendum A, 1969.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.9 establish the general requirements applicable to all Specifications in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the plant is in the MODES or other specified conditions of the Applicability statement of each Specification).
LCO 3.0.2	LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that: a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified. There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the plant in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the plant that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of (continued)

BASES

LCO 3.0.2 (continued)

safety for continued operation Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.9, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the plant may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

(continued)

BASES

LCO 3.0.3 (continued)

b. The condition of the plant is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the plant. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the plant in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the plant, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times. A plant shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

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BASES

LCO 3.0.3 (continued)

The time limits of LCO 3.0.3 allow 37 hours for the plant to be in MODE 4 when a shutdown is required during MODE 1 operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 4, or other applicable MODE, is not reduced. For example, if MODE 2 is reached in 2 hours, then the time allowed for reaching MODE 3 is the next 11 hours, because the total time for reaching MODE 3 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, and 3, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 4 and 5 because the plant is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a plant shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the plant. An example of this is in LCO 3.7.7, "Spent Fuel Storage Pool Water Level." LCO 3.7.7 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.7 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the plant in a shutdown condition. The Required Action of LCO 3.7.7 to "Suspend movement of irradiated fuel assemblies in the spent fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the plant in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when plant conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

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BASES

LCO 3.0.4 (continued)

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the plant for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the plant before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows 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, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior

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BASES

LCO 3.0.4 (continued)

to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., RCS Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

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BASES

LCO 3.0.4 (continued)

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any plant shutdown. In this context, a plant shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, and MODE 3 to MODE 4.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the plant is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

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BASES

LCO 3.0.5 (continued)

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system's LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support systems' LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCO's Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

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BASES

LCO 3.0.6 (continued)

Specification 5.5.12, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross division checks to identify a loss of safety function for those support systems that support safety systems are required. The cross division check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. A loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B3.0.6-1); or

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B3.0.6-2); or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B3.0.6-3).

<u>EXAMPLE B3.0.6-1</u>

If System 2 of Division A is inoperable, and System 5 of Division B is inoperable, a loss of safety function exists in supported System 5.

<u>EXAMPLE B3.0.6-2</u>

If System 2 of Division A is inoperable, and System 11 of Division B is inoperable, a loss of safety function exists in System 11 which in turn is supported by System 5.

<u>EXAMPLE B3.0.6-3</u>

If System 2 of Division A is inoperable, and System 1 of Division B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

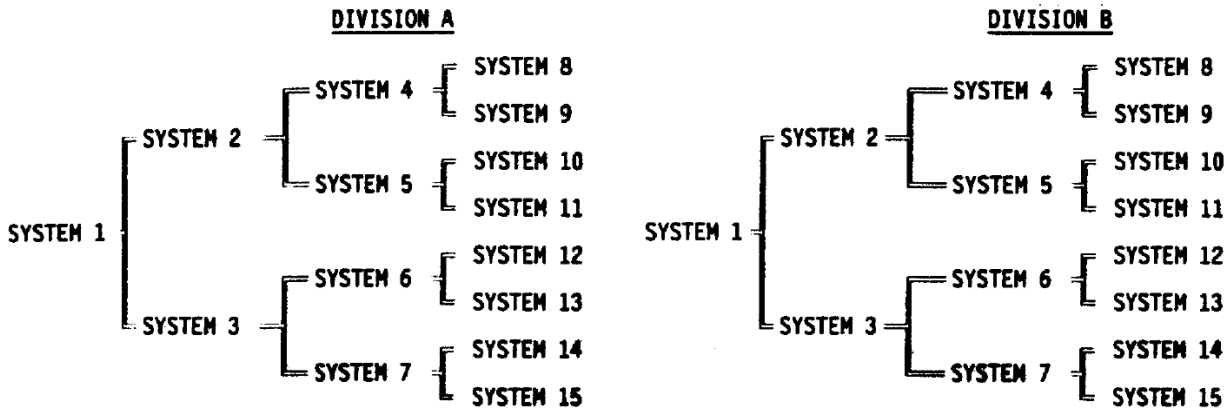
If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

(continued)

BASES

LCO 3.0.6
(continued)

EXAMPLES



(continued)

BASES

LCO 3.0.6 (continued)

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable emergency diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the plant. These special tests and operations are necessary to demonstrate select plant performance characteristics, to perform special maintenance activities, and to perform special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the

(continued)

BASES

LCO 3.0.7 (continued)

appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the Special Operations LCO shall be followed. When a Special Operations LCO requires another LCO to be met, only the requirements of the LCO statement are required to be met regardless of that LCO's Applicability (i.e., should the requirements of this other LCO not be met, the ACTIONS of the Special Operations LCO apply, not the ACTIONS of the other LCO). However, there are instances where the Special Operations LCO's ACTIONS may direct the other LCO's ACTIONS be met. The Surveillances of the other LCO are not required to be met, unless specified in the Special Operations LCO. If conditions exist such that the Applicability of any other LCO is met, all the other LCO's requirements (ACTIONS and SRs) are required to be met concurrent with the requirements of the Special Operations LCO.

LCO 3.0.8

Specification 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This Specification states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the TSs under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO must be declared not met and the associated ACTION requirements shall be met in accordance with Specification 3.0.2.

Specification 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. Specification 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72-hour Completion Time is reasonable based on the low probability of a seismic event concurrent

(continued)

BASES

LCO 3.0.8 (continued)

with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

Specification 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. Specification 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

The following configuration restrictions shall be applied to the use of Specification 3.0.8:

(1) Specification 3.0.8.a can only be used if one of the following two means of heat removal is available:

a. At least one high pressure makeup path (e.g., using High Pressure Coolant Injection (HPCI) or Reactor Core Isolation Cooling (RCIC) or its equivalent) and heat removal capability (e.g., suppression pool cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s), or

b. At least one low pressure makeup path (e.g., Low Pressure Coolant Injection (LPCI) or Core Spray (CS)) and heat removal capability (e.g., suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s).

(2) Specification 3.0.8.b can only be used following verification that at least one success path exists, using equipment not associated with the inoperable snubber(s), to provide makeup and core cooling needed to mitigate Loss of Offsite Power (LOOP) accident sequences (i.e., initiated by a seismically-induced LOOP event with concurrent loss of all safety system trains supported by the out-of-service snubbers).

Specification 3.0.8 only applies to the seismic function of snubbers; it does not apply to the non-seismic functions of snubbers. Therefore, each use of Specification 3.0.8 for seismic snubbers that also have

(continued)

BASES

LCO 3.0.8 (continued)

non-seismic functions requires confirmation that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. In addition, a record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic), implementation and compliance with the configuration restrictions defined above, and the associated plant configuration shall be available on a recoverable basis for NRC inspection.

Specification 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (i.e., the Maintenance Rule) does not address seismic risk. However, use of Specification 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

LCO 3.0.9

LCO 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions. LCO 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

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BASES

LCO 3.0.9 (continued)

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of LCO 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

(continued)

BASES

LCO 3.0.9 (continued)

LCO 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

The HPCI (High Pressure Coolant Injection) and RCIC (Reactor Core Isolation Cooling) systems are single train systems for injecting makeup water into the reactor during an accident or transient event. The RCIC system is not an Engineered Safeguard System and no credit is taken in the safety analyses for RCIC System operation. The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions. The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The ADS (Automatic Depressurization System) and low pressure ECCS coolant injection provide the core cooling function in the event of failure of the HPCI system during an accident. Thus, for the purposes of LCO 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and LCO 3.0.9 can be used on these single train systems in a manner similar to multiple train or subsystem systems.

If during the time that LCO 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified

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BASES

LCO 3.0.9 (continued)

given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g., CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the plant is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Special Operations LCO are only applicable when the Special Operations LCO is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR.

(continued)

BASES

SR 3.0.1 (continued)

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post-work testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post-work testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary plant parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed. Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at ≥ 800 psig. However, if other appropriate testing is satisfactorily completed and the scram time testing of SR 3.1.4.3 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 800 psig to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post-work testing.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

(continued)

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is the Primary Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

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BASES

SR 3.0.3 (continued)

The basis for this delay period includes consideration of plant conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified plant conditions, operating conditions, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity.

The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to plant conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of

(continued)

BASES

SR 3.0.3 (continued)

depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the plant. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance(s) not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1,

(continued)

BASES

SR 3.0.4 (continued)

which states that Surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any plant shutdown. In this context, a plant shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3 and MODE 3 to MODE 4.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

SDM requirements are specified to ensure:

a. The reactor can be made subcritical from all operating conditions and transients and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits; and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

These requirements are satisfied by the control rods, as described in the Updated Final Safety Analysis Report (UFSAR) Section 16.6 (Ref. 1), which can compensate for the reactivity effects of the fuel and water temperature changes experienced during all operating conditions.

APPLICABLE SAFETY ANALYSES

The control rod drop accident (CRDA) analysis (Refs. 2 and 3) assumes the core is subcritical with the highest worth control rod withdrawn. Typically, the first control rod withdrawn has a very high reactivity worth and, should the core SDM be substantially less than 0.38% $\Delta k/k$ during the withdrawal of the first control rod, the consequences of a CRDA could exceed the fuel damage limits for a CRDA (see Bases for LCO 3.1.6, "Rod Pattern Control"). Also, SDM is assumed as an initial condition for the control rod removal error during refueling (Ref. 4) and fuel assembly insertion error during refueling (Ref. 5) accidents. The analysis of these reactivity insertion events assumes the refueling interlocks are OPERABLE when the reactor is in the refueling mode of operation. These interlocks prevent the withdrawal of more than one control rod from the core during refueling. (Special consideration and requirements for multiple control rod withdrawal during refueling are covered in Special Operations LCO 3.10.6, "Multiple Control Rod Withdrawal - Refueling.") The analysis assumes this condition is acceptable since the core will be shut down with the highest worth control rod withdrawn, if adequate SDM has been demonstrated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Prevention or mitigation of reactivity insertion events is necessary to limit energy deposition in the fuel to prevent significant fuel damage, which could result in undue release of radioactivity. Adequate SDM ensures inadvertent criticalities and potential CRDAs involving high worth control rods (namely the first control rod withdrawn) will not cause significant fuel damage.

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

LCO

The specified SDM limit accounts for the uncertainty in the demonstration of the SDM by analysis or by a combination of test and analysis. A SDM limit is provided where the highest worth control rod is determined analytically. SDM is demonstrated by analysis or by a combination of test and analysis. During refueling it is demonstrated by analysis and during a startup it is demonstrated by a combination of test and analysis. To ensure adequate SDM during the design process, a design margin is included to account for uncertainties in the design calculations (Ref. 6).

APPLICABILITY

In MODES 1 and 2, SDM must be provided because subcriticality with the highest worth control rod withdrawn is assumed in the CRDA analysis (Ref. 2). In MODES 3 and 4, SDM is required to ensure the reactor will be held subcritical with margin for a single withdrawn control rod. SDM is required in MODE 5 to prevent an open vessel, inadvertent criticality during the withdrawal of a single control rod from a core cell containing one or more fuel assemblies or a fuel assembly insertion error (Ref. 7).

ACTIONS

A.1

With SDM not within the limits of the LCO in MODE 1 or 2, SDM must be restored within 6 hours. Failure to meet the specified SDM may be caused by a control rod that cannot be inserted. The allowed Completion Time of 6 hours is acceptable, considering that the reactor can still be shut down, assuming no failures of additional control rods to insert, and the low probability of an event occurring during this interval.

(continued)

BASES

ACTIONS (continued)

B.1

If the SDM cannot be restored, the plant must be brought to MODE 3 in 12 hours, to prevent the potential for further reductions in available SDM (e.g., additional stuck control rods). 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.

C.1

With SDM not within limits in MODE 3, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This action results in the least reactive condition for the core.

D.1, D.2, D.3, and D.4

With SDM not within limits in MODE 4, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This action results in the least reactive condition for the core. Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes ensuring secondary containment is OPERABLE; at least one Standby Gas Treatment (SGT) subsystem is OPERABLE; and secondary containment isolation capability is available in each associated secondary containment penetration flow path not isolated that is assumed to isolate to mitigate radioactivity releases (i.e., at least one secondary containment isolation valve and associated instrumentation are OPERABLE, or acceptable administrative controls assure isolation capability. These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated). This may be performed as an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not

(continued)

BASES

ACTIONS

D.1, D.2, D.3, and D.4 (continued)

necessary to perform the surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, SRs may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

E.1, E.2, E.3, E.4, and E.5

With SDM not within limits in MODE 5, the operator must immediately suspend CORE ALTERATIONS that could reduce SDM (e.g., insertion of fuel in the core or the withdrawal of control rods). Suspension of these activities shall not preclude completion of movement of a component to a safe condition. Inserting control rods or removing fuel from the core will reduce the total reactivity and are therefore excluded from the suspended actions.

Action must also be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies have been fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and therefore do not have to be inserted.

Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes ensuring secondary containment is OPERABLE; at least one SGT subsystem is OPERABLE; and secondary containment isolation capability is available in each associated secondary containment penetration flow path not isolated that is assumed to isolate to mitigate radioactivity releases (i.e., at least one secondary containment isolation valve and associated instrumentation are OPERABLE, or acceptable administrative controls assure isolation capability. These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated). This may be performed as an

(continued)

BASES

ACTIONS

E.1, E.2, E.3, E.4, and E.5 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

Adequate SDM must be verified to ensure that the reactor can be made subcritical from any initial operating condition with the highest reactivity worth control rod fully withdrawn and all other control rods fully inserted. This can be accomplished by a test (by withdrawing control rods), an evaluation, or a combination of the two. Adequate SDM is demonstrated by testing before or during the first startup after fuel movement, shuffling within the reactor pressure vessel, or control rod replacement. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Since core reactivity will vary during the cycle as a function of fuel depletion and poison burnup, the beginning of cycle (BOC) test must also account for changes in core reactivity during the cycle. Therefore, to obtain the SDM, the initial measured value must be increased by an adder, "R", which is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated BOC core reactivity. If the value of R is negative (that is, BOC is the most reactive point in the cycle), no correction to the BOC measured value is required (Ref. 6).

The SDM may be demonstrated during an in-sequence control rod withdrawal or during local criticals. In both cases, the highest worth control rod is analytically determined. Local critical tests require the withdrawal of out of sequence control rods. This testing would therefore require bypassing of the rod worth minimizer to allow the out of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

sequence withdrawal, and therefore additional requirements must be met (see LCO 3.10.7, "Control Rod Testing–Operating" and LCO 3.10.8, "SHUTDOWN MARGIN Test–Refueling").

The Frequency of 4 hours after reaching criticality is allowed to provide a reasonable amount of time to perform the required calculations and have appropriate verification.

During MODES 3 and 4, analytical calculation of SDM may be used to assure the requirements of SR 3.1.1.1 are met. During MODE 5, adequate SDM is required to ensure that the reactor does not reach criticality during control rod withdrawals. An evaluation of each in-vessel fuel movement during fuel loading (including shuffling fuel within the core) is required to ensure adequate SDM is maintained during refueling. This evaluation ensures that the intermediate loading patterns are bounded by the safety analyses for the final core loading pattern. For example, bounding analyses that demonstrate adequate SDM for the most reactive configurations during the refueling may be performed to demonstrate acceptability of the entire fuel movement sequence. These bounding analyses include additional margins to the associated uncertainties. Spiral offload/reload sequences inherently satisfy the SR, provided the fuel assemblies are reloaded in the same configuration analyzed for the new cycle. Removing fuel from the core will always result in an increase in SDM.

REFERENCES

1. UFSAR, Section 16.6.

2. UFSAR, Section 14.6.1.2.

3. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, Supplement for United States, Section S.2.2.3.1, (Revision specified in the COLR).

4. UFSAR, Section 14.5.4.3.

5. 10 CFR 50.36(c)(2)(ii).

6. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, Section 3.2.4.1, (Revision specified in the COLR).

7. UFSAR, Section 14.5.4.4.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Anomalies

BASES

BACKGROUND

In accordance with the Updated Final Safety Evaluation Report (UFSAR) Section 16.6 (Ref. 1), reactivity shall be controllable such that subcriticality is maintained under cold conditions and acceptable fuel design limits are not exceeded during normal operation and abnormal operational transients. Therefore, Reactivity Anomalies are used as a measure of the predicted versus measured (i.e., monitored) core reactivity during power operation. The continual confirmation of core reactivity is necessary to ensure that the Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity anomaly could be the result of unanticipated changes in fuel reactivity or control rod worth or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM requirements (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in assuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers, producing zero net reactivity.

In order to achieve the required fuel cycle energy output, the uranium enrichment in the new fuel loading and the fuel loaded in the previous cycles provide excess positive reactivity beyond that required to sustain steady state operation at the beginning of cycle (BOC). When the reactor is critical at RTP and operating moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, and whatever neutron poisons (mainly xenon and samarium) are present in the fuel. The predicted core reactivity, as represented by core k_{eff}, is calculated by the 3D Monicore System as a function of cycle exposure. This calculation is performed for projected

(continued)

BASES

BACKGROUND (continued)

operating states and conditions throughout the cycle. The monitored k_{eff} is calculated by the core monitoring system t actual plant conditions and is compared to the predicted value at the same cycle exposure.

APPLICABLE SAFETY ANALYSIS

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations (Ref. 2). In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod drop accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Measuring reactivity anomaly provides additional assurance that the nuclear methods provide an accurate representation of the core reactivity.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted core k_{eff} for identical core conditions at BOC do not reasonably agree, then the assumptions used in the reload cycle design analysis or the calculation models used to predict core k_{eff} may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured value. Thereafter, any significant deviations in the measured core k_{eff} from the predicted core k_{eff} that develop during fuel depletion may be an indication that the assumptions of the DBA and transient analyses are no longer valid, or that an unexpected change in core conditions has occurred.

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

LCO

The reactivity anomaly limit is established to ensure plant operation is maintained within the assumptions of the safety analyses. Large differences between measured and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the "Nuclear Design Methodology" are larger than expected. A limit on the difference between the measured and the predicted core k_{eff} of ± 1% Δ k/k has been established based on engineering judgment. A > 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

(continued)

BASES (continued)

APPLICABILITY

In MODE 1, most of the control rods are withdrawn and steady state operation is typically achieved. Under these conditions. the comparison between predicted and measured core reactivity provides an effective measure of the reactivity anomaly. In MODE 2, control rods are typically being withdrawn during a startup. In MODES 3 and 4, All control rods are fully inserted and therefore the reactor is in the least reactive state. where measuring core reactivity is not necessary. In MODE 5, fuel loading results in a continually changing core reactivity. SDM requirements (LCO 3.1.1) ensure that fuel movements are performed within the bounds of the safety analysis. and an SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement. control rod replacement. shuffling). The SDM test, required by LCO 3.1.1, provides a direct comparison of the predicted and measured core reactivity at cold conditions; therefore, the Reactivity Anomalies Specification is not required during these conditions.

ACTIONS

A.1

Should an anomaly develop between measured and predicted core reactivity. the core reactivity difference must be restored to within the limit to ensure continued operation is within the core design assumptions. Restoration to within the limit could be performed by an evaluation of the core design and safety analysis to determine the reason for the anomaly. This evaluation normally reviews the core conditions to determine their consistency with input to design calculations. Measured core and process parameters are also normally evaluated to determine that they are within the bounds of the safety analysis. and safety analysis calculational models may be reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

(continued)

BASES

ACTIONS (continued)

B.1

If the core reactivity cannot be restored to within the 1% Δ k/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status. the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Verifying the reactivity difference between the measured and predicted core k_{eff} is within the limits of the LCO provides added assurance that plant operation is maintained within the assumptions of the DBA and transient analyses. The 3D Monicore System calculates the core k_{eff} for the reactor conditions obtained from plant instrumentation. A comparison of the measured core k_{eff} to the predicted core k_{eff} at the same cycle exposure is used to calculate the reactivity difference. The comparison is required when the core k_{eff} has potentially changed by a significant amount. This may occur following a refueling in which new fuel assemblies are loaded, fuel assemblies are shuffled within the core, or control rods are replaced or shuffled. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Also, core reactivity changes during the cycle. The 24 hour interval after reaching equilibrium conditions following a startup is based on the need for equilibrium xenon concentrations in the core. such that an accurate comparison between the measured and predicted core k_{eff} can be made. For the purposes of this SR, the reactor is assumed to be at equilibrium conditions when steady state operations (no control rod movement or core flow changes) at ≥ 75% RTP have been obtained. The 1000 MWD/T Frequency was developed, considering the relatively slow change in core reactivity with exposure and operating experience related to variations in core reactivity. This comparison requires the core to be operating at power levels which minimize the uncertainties and measurement errors, in order to obtain meaningful results. Therefore, the comparison is only done when in MODE 1. The tests performed at this Frequency also use base data obtained during the first test of the specific cycle.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Chapter 14.
3. 10 CFR 50.36(c)(2)(ii).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Control Rod OPERABILITY

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, which is the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes to ensure under conditions of normal operation, including abnormal operational transients, that specified acceptable fuel design limits are not exceeded. In addition, the control rods provide the capability to hold the reactor core subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System. The CRD System is designed to satisfy the requirements specified in Reference 1.

The CRD System consists of 137 locking piston CRDs and a hydraulic control unit for each CRD. The locking piston type CRD is a double acting hydraulic piston, which uses condensate water as the operating fluid. Accumulators provide additional energy for scram. An index tube and piston, coupled to the control rod, are locked at fixed increments by a collet mechanism. The collet fingers engage notches in the index tube to prevent unintentional withdrawal of the control rod, but without restricting insertion.

This Specification, along with LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators," ensure that the performance of the control rods in the event of a Design Basis Accident (DBA) or transient meets the assumptions used in the safety analyses of References 2 and 3.

APPLICABLE SAFETY ANALYSES

The control rods provide the primary means for rapid reactivity control (reactor scram), for maintaining the reactor subcritical and for limiting the potential effects of reactivity insertion events caused by malfunctions in the CRD System.

The capability to insert the control rods provides assurance that the assumptions for scram reactivity in the DBA and transient analyses are not violated (Refs. 2 and 3). Since the SDM ensures the reactor will be subcritical with the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

highest worth control rod withdrawn (assumed single failure), the additional failure of a second control rod to insert, if required, could invalidate the demonstrated SDM and potentially limit the ability of the CRD System to hold the reactor subcritical. If the control rod is stuck at an inserted position and becomes decoupled from the CRD, a control rod drop accident (CRDA) can possibly occur. Therefore, the requirement that all control rods be OPERABLE ensures the CRD System can perform its intended function.

The control rods also protect the fuel from damage which could result in release of radioactivity. The limits protected are the MCPR Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)", and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), and the fuel damage limit (see Bases for LCO 3.1.6, "Rod Pattern Control") during reactivity insertion events.

The negative reactivity insertion (scram) provided by the CRD System provides the analytical basis for determination of plant thermal limits and provides protection against fuel damage limits during a CRDA. The Bases for LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6 discuss in more detail how the SLs are protected by the CRD System.

Control rod OPERABILITY satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

The OPERABILITY of an individual control rod is based on a combination of factors, primarily, the scram insertion times, the control rod coupling integrity, and the ability to determine the control rod position. Accumulator OPERABILITY is addressed by LCO 3.1.5. The associated scram accumulator status for a control rod only affects the scram insertion times; therefore, an inoperable accumulator does not immediately require declaring a control rod inoperable.

Although not all control rods are required to be OPERABLE to satisfy the intended reactivity control requirements, strict control over the number and distribution of inoperable control rods is required to satisfy the assumptions of the DBA and transient analyses.

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BASES (continued)

APPLICABILITY

In MODES 1 and 2, the control rods are assumed to function during a DBA or transient and are therefore required to be OPERABLE in these MODES. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions. Control rod requirements in MODE 5 are located in LCO 3.9.5, "Control Rod OPERABILITY – Refueling."

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each control rod. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable control rod. Complying with the Required Actions may allow for continued operation, and subsequent inoperable control rods are governed by subsequent Condition entry and application of associated Required Actions.

A.1, A.2, A.3, and A.4

A control rod is considered stuck if it will not insert by either CRD drive water or scram pressure. With a fully inserted control rod stuck, no actions are required as long as the control rod remains fully inserted. The Required Actions are modified by a Note, which allows the rod worth minimizer (RWM) to be bypassed if required to allow continued operation. LCO 3.3.2.1, "Control Rod Block Instrumentation," provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis. With one withdrawn control rod stuck, the local scram reactivity rate assumptions may not be met if the stuck control rod separation criteria are not met. Therefore, a verification that the separation criteria are met must be performed immediately. The separation criteria are not met if a) the stuck control rod occupies a location adjacent to two "slow" control rods, b) the stuck control rod occupies a location adjacent to one "slow" control rod, and the one "slow" control rod is also adjacent to another "slow" control rod, or c) if the stuck control rod occupies a location adjacent to one "slow" control rod when there is another pair of "slow" control rods adjacent to one another. The description of "slow" control rods is provided in LCO 3.1.4, "Control Rod Scram Times." In addition, the

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

associated control rod drive must be disarmed (hydraulically) in 2 hours. The allowed Completion Time of 2 hours is acceptable, considering the reactor can still be shut down, assuming no additional control rods fail to insert, and provides a reasonable time to perform the Required Action in an orderly manner. The control rod must be isolated from both scram and normal insert and withdraw pressure. Isolating the control rod in this manner prevents damage to the stuck CRD. In addition, the control rod should be isolated while maintaining cooling water to the CRD.

Demonstrating the insertion capability of each withdrawn control rod must also be performed within 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM. SR 3.1.3.2 requires periodic tests of the control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Required Action A.3 Completion Time only begins upon discovery of Condition A concurrent with THERMAL POWER greater than the actual LPSP of the RWM since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The allowed Completion Time of 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the LPSP of the RWM provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests.

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion, an additional control rod would have to be assumed to fail to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

reactivity. Failure to reach MODE 4 condition is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach and maintain MODE 3 conditions (Ref. 5).

B.1

With two or more withdrawn control rods stuck, the plant must be brought to MODE 3 within 12 hours. The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. 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.

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action C.1 is modified by a Note, which allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

D.1 and D.2

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At ≤ 10% RTP, the generic banked position withdrawal sequence (BPWS) analysis (Ref. 5) requires inserted control rods not in compliance with BPWS to be separated by at least two OPERABLE control rods in all directions, including the diagonal. Therefore, if two or more inoperable control rods are not in compliance with BPWS and not separated by at least two OPERABLE control rods, action must be taken to restore compliance with BPWS or restore the control rods to OPERABLE status. Condition D is modified by a Note indicating that the Condition is not applicable when > 10% RTP, since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met, or there are nine or more inoperable control rods, 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. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 10% RTP (i.e., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods (such as taking voltage measurements using the position indicator probe connectors and determining the position using the resultant readings). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.3.2

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. These Surveillances are not required when THERMAL POWER is less than or equal to the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of the Banked Position Withdrawal Sequence (BPWS) (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. At any time, if a control rod is immovable, a determination of the control rods OPERABILITY must be made and appropriate action taken. This SR is modified by a Note that allows 31 days, after withdrawal of the control rod and increasing power to above the LPSP of the RWM, to perform the Surveillance. This acknowledges that the control rod must be first withdrawn and THERMAL POWER must increase to above the LPSP before performance of the Surveillance, and therefore the Notes avoid potential conflicts with SR 3.0.3 and SR 3.0.4.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.3.3

Verifying that the scram time for each control rod to notch position 04 is ≤ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.4

Coupling verification is performed to ensure the control rod is connected to the CRD and will perform its intended function when necessary. The Surveillance requires verifying a control rod does not go to the withdrawn overtravel position. The overtravel position feature provides a positive check on the coupling integrity since only an uncoupled CRD can reach the overtravel position. The verification is required to be performed any time a control rod is withdrawn to the "full out" position (notch position 48) or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This includes control rods inserted one notch and then returned to the "full out" position during the performance of SR 3.1.3.2. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.

Coupling verification is required to support the administrative controls of the improved BPWS control rod insertion process. When performing a shutdown of the plant, an optional BPWS control rod sequence (Ref. 6) may be used provided that all withdrawn control rods have been confirmed

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.4 (continued)

to be coupled. The rods may be inserted without the need to stop at intermediate positions since the possibility of a CRDA is eliminated by the confirmation that withdrawn control rods are coupled.

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 14.6.
3. UFSAR, Section 14.5.
4. 10 CFR 50.36(c)(2)(ii).
5. NEDO-21231, Banked Position Withdrawal Sequence, Section 7.2, January 1977.
6. NEDO-33091-A, Revision 2, Improved BPWS Control Rod Insertion Process, July 2004.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Control Rod Scram Times

BASES

BACKGROUND

The scram function of the Control Rod Drive (CRD) System controls reactivity changes during abnormal operational transients to ensure that specified acceptable fuel design limits are not exceeded (Ref. 1). The control rods are scrammed by positive means using hydraulic pressure exerted on the CRD piston.

When a scram signal is initiated, control air is vented from the scram valves, allowing them to open by spring action. Opening the exhaust valve reduces the pressure above the main drive piston to atmospheric pressure, and opening the inlet valve applies the accumulator or reactor pressure to the bottom of the piston. Since the notches in the index tube are tapered on the lower edge, the collet fingers are forced open by cam action, allowing the index tube to move upward without restriction because of the high differential pressure across the piston. As the drive moves upward and the accumulator pressure reduces below the reactor pressure, a ball check valve opens, letting the reactor pressure complete the scram action. If the reactor pressure is low, such as during startup, the accumulator will fully insert the control rod in the required time without assistance from reactor pressure.

APPLICABLE SAFETY ANALYSES

The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate (Refs. 2 and 3). The resulting negative scram reactivity forms the basis for the determination of plant thermal limits (e.g., the MCPR). Other distributions of scram times (e.g., several control rods scramming slower than the average time with several control rods scramming faster than the average time) can also provide sufficient scram reactivity. Surveillance of each individual control rod's scram time ensures the scram reactivity assumed in the DBA and transient analyses can be met.

The scram function of the CRD System protects the MCPR Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

RATE (APLHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded. Above 800 psig, the scram function is designed to insert negative reactivity at a rate fast enough to prevent the actual MCPR from becoming less than the MCPR SL, during the analyzed limiting power transient. Below 800 psig, the scram function is assumed to mitigate the control rod drop accident (Ref. 4) and, therefore, also provides protection against violating fuel damage limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control"). For the reactor vessel overpressure protection analysis, the scram function, along with the safety/relief valves, ensure that the peak vessel pressure is maintained within the applicable ASME Code limits.

Control rod scram times satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

The scram times specified in Table 3.1.4-1 are required to ensure that the scram reactivity assumed in the DBA and transient analysis is met (Ref. 6). To account for single failures and "slow" scramming control rods, the scram times specified in Table 3.1.4-1 are faster than those assumed in the design basis analysis. The scram times have a margin that allows 10 control rods to have scram times exceeding the specified limits (i.e., "slow" control rods) assuming a single stuck control rod (as allowed by LCO 3.1.3, "Control Rod OPERABILITY") and an additional control rod failing to scram per the single failure criterion. The scram times are specified as a function of reactor steam dome pressure to account for the pressure dependence of the scram times. The scram times are specified relative to measurements based on reed switch positions, which provide the control rod position indication. The reed switch closes ("pickup") when the index tube passes a specific location and then opens ("dropout") as the index tube travels upward. Verification of the specified scram times in Table 3.1.4-1 is accomplished through measurement of the "dropout" times. To ensure that local scram reactivity rates are maintained within acceptable limits, no more than two of the allowed "slow" control rods may occupy adjacent locations.

Table 3.1.4-1 is modified by two Notes which state that control rods with scram times not within the limits of the table are considered "slow" and that control rods with scram times > 7 seconds are considered inoperable as required by SR 3.1.3.3.

(continued)

BASES

LCO (continued)

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

APPLICABILITY

In MODES 1 and 2, a scram is assumed to function during transients and accidents analyzed for these plant conditions. These events are assumed to occur during startup and power operation; therefore, the scram function of the control rods is required during these MODES. In MODES 3 and 4, the control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram capability during these conditions. Scram requirements in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY – Refueling."

ACTIONS

A.1

When the requirements of this LCO are not met, the rate of negative reactivity insertion during a scram may not be within the assumptions of the safety analyses. Therefore, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 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

The four SRs of this LCO are modified by a Note stating that during a single control rod scram time surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated, (i.e., charging valve closed) the influence of the CRD pump head does not affect the single control rod scram times. During a full core scram, the CRD pump head would be seen by all control rods and would have a negligible effect on the scram insertion times.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.1

The scram reactivity used in DBA and transient analyses is based on an assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure ≥ 800 psig demonstrates acceptable scram times for the transients analyzed in References 3 and 4.

Maximum scram insertion times occur at a reactor steam dome pressure of approximately 800 psig because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure ≥ 800 psig ensures that the measured scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure that scram time testing is performed within a reasonable time following a shutdown duration of ≥ 120 days, control rods are required to be tested before exceeding 40% RTP following the shutdown. This Frequency is acceptable considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by fuel movement within the associated core cell and by work on control rods or the CRD System.

SR 3.1.4.2

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods. The sample remains representative if no more than 7.5% of the control rods in the sample tested are determined to be "slow." With more than 7.5% of the sample declared to be "slow" per the criteria in Table 3.1.4-1, additional control rods are tested until this 7.5% criterion (i.e., 7.5% of the entire sample size) is satisfied, or until the total number of "slow" control rods (throughout the core, from all surveillances) exceeds the LCO limit. For planned testing, the control rods selected for the sample should be different for each test. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.2 (continued)

data may have been previously tested in a sample. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.4.3

When work that could affect the scram insertion time is performed on a control rod or the CRD System, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate the affected control rod is still within acceptable limits. The limits for reactor pressures < 800 psig are found in the Technical Requirements Manual (Ref. 7) and are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 800 psig. Limits for ≥ 800 psig are found in Table 3.1.4-1. If testing demonstrates the affected control rod does not meet these limits, but is within the 7-second limit of Table 3.1.4-1, Note 2, the control rod can be declared OPERABLE and "slow."

Specific examples of work that could affect the scram times are (but are not limited to) the following: removal of any CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram pilot valve, scram valve, accumulator, isolation valve or check valve in the piping required for scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.4

When work that could affect the scram insertion time is performed on a control rod or CRD System, or when fuel movement within the reactor pressure vessel occurs, testing must be done to demonstrate each affected control rod is still within the limits of Table 3.1.4-1 with the reactor steam dome pressure ≥ 800 psig. Where work has been performed at high reactor pressure (≥ 800 psig), the requirements of SR 3.1.4.3 and SR 3.1.4.4 can be satisfied with one test. For a control rod affected by work performed while at low pressure (< 800 psig), however, a low pressure and high pressure test may be required. This testing ensures that, prior to withdrawing the control rod for continued operation, the control rod scram performance is acceptable for operating reactor pressure conditions. Alternatively, a control rod scram test during hydrostatic pressure testing could also satisfy both criteria. When fuel movement occurs within the reactor pressure vessel, only those control rods associated with the core cells affected by the fuel movement are required to be scram time tested. During a routine refueling outage it is expected that all control rods will be affected.

The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

REFERENCES

1. UFSAR, Section 16.6.

2. UFSAR, Section 14.6.

3. UFSAR, Section 14.5.

4. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, Supplement for United States, Section S.2.2.3.1, (Revision specified in the COLR).

5. 10 CFR 50.36(c)(2)(ii).

6. Letter from R.F. Janecek (BWROG) to R.W. Starostecki (NRC), BWR Owners Group Revised Reactivity Control System Technical Specifications, BWROG-8754, September 17, 1987.

7. Technical Requirements Manual.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Control Rod Scram Accumulators

BASES

BACKGROUND

The control rod scram accumulators are part of the Control Rod Drive (CRD) System and are provided to ensure that the control rods scram under varying reactor conditions. The control rod scram accumulators store sufficient energy to fully insert a control rod at any reactor vessel pressure. The accumulator is a hydraulic cylinder with a free floating piston. The piston separates the water used to scram the control rods from the nitrogen, which provides the required energy. The scram accumulators are necessary to scram the control rods within the required insertion times of LCO 3.1.4, "Control Rod Scram Times."

APPLICABLE SAFETY ANALYSES

The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate (Refs. 1 and 2). OPERABILITY of each individual control rod scram accumulator, along with LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.4, ensures that the scram reactivity assumed in the DBA and transient analyses can be met. The existence of an inoperable accumulator may invalidate prior scram time measurements for the associated control rod.

The scram function of the CRD System, and therefore the OPERABILITY of the accumulators, protects the MCPR Safety Limit (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded (see Bases for LCO 3.1.4). In addition, the scram function at low reactor vessel pressure (i.e., startup conditions) provides protection against violating fuel design limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control").

Control rod scram accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

(continued)

BASES (continued)

LCO

The OPERABILITY of the control rod scram accumulators is required to ensure that adequate scram insertion capability exists when needed over the entire range of reactor pressures. The OPERABILITY of the scram accumulators is based on maintaining adequate accumulator pressure.

APPLICABILITY

In MODES 1 and 2, the scram function is required for mitigation of DBAs and transients, and therefore the scram accumulators must be OPERABLE to support the scram function. In MODES 3 and 4, control rods are not capable of being withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram accumulator OPERABILITY during these conditions. Requirements for scram accumulators in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY – Refueling."

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each control rod scram accumulator. This is acceptable since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable accumulator. Complying with the Required Actions may allow for continued operation.

A.1 and A.2

With one control rod scram accumulator inoperable and the reactor steam dome pressure ≥ 900 psig, the control rod may be declared "slow," since the control rod will still scram at the reactor operating pressure but may not satisfy the required scram times in Table 3.1.4-1.

Required Action A.1 is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control scram time was within the limits of Table 3.1.4-1 during the last scram time test. Otherwise, the control rod would already be considered "slow" and the further degradation of scram performance with an inoperable accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action A.2) and LCO 3.1.3 is entered. This would result in requiring the affected control rod to be fully inserted and disarmed, thereby satisfying its intended function, in accordance with ACTIONS of LCO 3.1.3.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The allowed Completion Time of 8 hours is reasonable, based on the large number of control rods available to provide the scram function and the ability of the affected control rod to scram only with reactor pressure at high reactor pressures.

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

With two or more control rod scram accumulators inoperable and reactor steam dome pressure ≥ 900 psig, adequate pressure must be supplied to the charging water header. With inadequate charging water pressure, all of the accumulators could become inoperable, resulting in a potentially severe degradation of scram performance. Therefore, within 20 minutes from discovery of charging water header pressure < 940 psig concurrent with Condition B, adequate charging water header pressure must be restored. The allowed Completion Time of 20 minutes is reasonable, to place a CRD pump into service to restore the charging water header pressure, if required. This Completion Time is based on the ability of the reactor pressure alone to fully insert all control rods.

The control rod may be declared "slow," since the control rod will still scram using only reactor pressure, but may not satisfy the times in Table 3.1.4-1. Required Action B.2.1 is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control scram time is within the limits of Table 3.1.4-1 during the last scram time test. Otherwise, the control rod would already be considered "slow" and the further degradation of scram performance with an inoperable accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action B.2.2) and LCO 3.1.3 entered. This would result in requiring the affected control rod to be fully inserted and disarmed, thereby satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 1 hour is reasonable, based on the ability of only the reactor pressure to scram the control rods and the low probability of a DBA or transient occurring while the affected accumulators are inoperable.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one or more control rod scram accumulators inoperable and the reactor steam dome pressure < 900 psig, the pressure supplied to the charging water header must be adequate to ensure that accumulators remain charged. With the reactor steam dome pressure < 900 psig, the function of the accumulators in providing the scram force becomes much more important since the scram function could become severely degraded during a depressurization event or at low reactor pressures. Therefore, immediately upon discovery of charging water header pressure < 940 psig, concurrent with Condition C, all control rods associated with inoperable accumulators must be verified to be fully inserted. Withdrawn control rods with inoperable accumulators may fail to scram under these low pressure conditions. The associated control rods must also be declared inoperable within 1 hour. The allowed Completion Time of 1 hour is reasonable for Required Action C.2, considering the low probability of a DBA or transient occurring during the time that the accumulator is inoperable.

D.1

The reactor mode switch must be immediately placed in the shutdown position if either Required Action and associated Completion Time associated with loss of the CRD charging
pump (Required Actions B.1 and C.1) cannot be met. This ensures that all insertable control rods are inserted and that the reactor is in a condition that does not require the active function (i.e., scram) of the control rods. This Required Action is modified by a Note stating that the action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

SR 3.1.5.1 requires that the accumulator pressure be checked periodically to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1 (continued)

inoperable. The minimum accumulator pressure of 940 psig is well below the expected pressure of approximately 1100 psig (Ref 4). Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.6.

2. UFSAR, Section 14.5.

3. 10 CFR 50.36(c)(2)(ii).

4. GEK-9582C, "Hydraulic Control Unit," December 1987.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Rod Pattern Control

BASES

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed over the operating range of all control rods inserted to 10% RTP. The sequences limit the potential amount of reactivity addition that could occur in the event of a Control Rod Drop Accident (CRDA).

This Specification assures that the control rod patterns are consistent with the assumptions of the CRDA analyses of References 1 and 2.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1 and 2. CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analysis. The RWM (LCO 3.3.2.1) provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analysis are not violated.

Prevention or mitigation of positive reactivity insertion events is necessary to limit the energy deposition in the fuel, thereby preventing significant fuel damage which could result in the undue release of radioactivity. Since the failure consequences for UO_2 have been shown to be insignificant below fuel energy depositions of 300 cal/gm (Ref. 3), the fuel energy deposition limit of 280 cal/gm provides a margin of safety from significant core damage which would result in release of radioactivity (Refs. 4 and 5). Generic evaluations (Refs. 1, 6, 7, 8 and 9) of a design basis CRDA (i.e., a CRDA resulting in a peak fuel energy deposition of 280 cal/gm) have shown that if the peak fuel enthalpy remains below 280 cal/gm, then the maximum reactor pressure will be less than the required ASME Code limits (Ref. 10) and the calculated offsite doses will be well within the required limits (Ref. 5). The calculated offsite doses remain within the limits since only a small number of fuel rods would reach a fuel enthalpy of 170 cal/gm, which is the enthalpy limit for eventual cladding perforation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Control rod patterns analyzed in Reference 1 follow the banked position withdrawal sequence (BPWS). The BPWS is applicable from the condition of all control rods fully inserted to 10% RTP (Ref. 2). For the BPWS, the control rods are required to be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions (e.g., between notches 08 and 12). The banked positions are established to minimize the maximum incremental control rod worth without being overly restrictive during normal plant operation. Generic analysis of the BPWS (Ref. 1) has demonstrated that the 280 cal/gm fuel energy deposition limit will not be violated during a CRDA while following the BPWS mode of operation. The generic BPWS analysis (Ref. 11) also evaluates the effect of fully inserted, inoperable control rods not in compliance with the sequence, to allow a limited number (i.e., eight) and distribution of fully inserted, inoperable control rods.

When performing a shutdown of the plant, an optional BPWS control rod sequence (Ref. 13) may be used provided that all withdrawn control rods have been confirmed to be coupled. The rods may be inserted without the need to stop at intermediate positions since the possibility of a CRDA is eliminated by the confirmation that withdrawn control rods are coupled. When using the Reference 13 control rod sequence for shutdown, the RWM may be reprogrammed to enforce the requirements of the improved BPWS control rod insertion. Should the RWM become inoperable, the RWM may be bypassed and the improved BPWS shutdown sequence implemented under LCO 3.3.2.1, Condition D controls.

In order to use the Reference 13 BPWS shutdown process, an extra check is required in order to consider a control rod to be "confirmed" to be coupled. This extra check ensures that no Single Operator Error can result in an incorrect coupling check. For purposes of this shutdown process, the method for confirming that control rods are coupled varies depending on the position of the control rod in the core. Details on this coupling confirmation requirement are provided in Reference 13, which requires that any partially inserted control rods, which have not been confirmed to be coupled since their last withdrawal, be fully inserted prior to reaching the LPSP. If a control rod has been checked for coupling at notch 48 and the rod has since only been moved inward, this rod is in contact with its drive and is not required to be fully inserted prior to reaching the LPSP. However, if it cannot be confirmed that the control rod has

(continued)

BASES

APPLICABLE SAFTEY ANALYSES (continued)

only been moved inward, then that rod shall be fully inserted prior to reaching the LPSP. This extra check may be performed as an administrative check, by examining logs, previous surveillances or other information. If the requirements for use of the BPWS control rod insertion process contained in Reference 13 are followed, the plant is considered to be in compliance with BPWS requirements, as required by LCO 3.1.6.

Rod pattern control satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 12).

LCO

Compliance with the prescribed control rod sequences minimizes the potential consequences of a CRDA by limiting the initial conditions to those consistent with the BPWS. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, "Control Rod OPERABILITY," consistent with the allowances for inoperable control rods in the BPWS.

APPLICABILITY

In MODES 1 and 2, when THERMAL POWER is ≤ 10% RTP, the CRDA is a Design Basis Accident and, therefore, compliance with the assumptions of the safety analysis is required. When THERMAL POWER is > 10% RTP, there is no credible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel energy deposition limit during a CRDA (Ref. 2). In MODES 3, 4, and 5, since the reactor is shut down and only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will remain subcritical with a single control rod withdrawn.

ACTIONS

A.1 and A.2

With one or more OPERABLE control rods not in compliance with the prescribed control rod sequence, actions may be taken to either correct the control rod pattern or declare the associated control rods inoperable within 8 hours. Noncompliance with the prescribed sequence may be the result of "double notching," drifting from a control rod drive cooling water transient, leaking scram valves, or a power reduction to ≤ 10% RTP before establishing the correct control rod pattern. The number of OPERABLE control rods

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

not in compliance with the prescribed sequence is limited to eight, to prevent the operator from attempting to correct a control rod pattern that significantly deviates from the prescribed sequence. When the control rod pattern is not in compliance with the prescribed sequence, all control rod movement should be stopped except for moves needed to correct the rod pattern, or scram if warranted.

Required Action A.1 is modified by a Note which allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator (Reactor Operator or Senior Reactor Operator) or reactor engineer. This ensures that the control rods will be moved to the correct position. A control rod not in compliance with the prescribed sequence is not considered inoperable except as required by Required Action A.2. OPERABILITY of control rods is determined by compliance with LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." The allowed Completion Time of 8 hours is reasonable, considering the restrictions on the number of allowed out of sequence control rods and the low probability of a CRDA occurring during the time the control rods are out of sequence.

B.1 and B.2

If nine or more OPERABLE control rods are out of sequence, the control rod pattern significantly deviates from the prescribed sequence. Control rod withdrawal should be suspended immediately to prevent the potential for further deviation from the prescribed sequence. Control rod insertion to correct control rods withdrawn beyond their allowed position is allowed since, in general, insertion of control rods has less impact on control rod worth than withdrawals have. Required Action B.1 is modified by a Note which allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator (Reactor Operator or Senior Reactor Operator) or reactor engineer.

When nine or more OPERABLE control rods are not in compliance with BPWS, the reactor mode switch must be placed in the shutdown position within 1 hour. With the mode

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

switch in shutdown, the reactor is shut down, and as such, does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

The control rod pattern is periodically verified to be in compliance with the BPWS to ensure the assumptions of the CRDA analyses are met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The RWM provides control rod blocks to enforce the required sequence and is required to be OPERABLE when operating at ≤ 10% RTP.

REFERENCES

1. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, Supplement for United States, Section S.2.2.3.1, (Revision specified in the COLR).

2. Letter from T.A. Pickens (BWROG) to G.C. Lainas (NRC), Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, BWROG-8644, August 15, 1986.

3. NUREG-0979, Safety Evaluation Report Related to the Final Design Approval of the GESSAR II, BWR/6 Nuclear Island Design (and Supplements 1 through 5), Section 4.2.1.3.2, April 1983.

4. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 15.4.9, Spectrum of Rod Drop Accidents (BWR), Revision 2, July 1981.

5. 10 CFR 100.

6. NEDO-10527, Rod Drop Accident Analysis For Large BWRs, March 1972.

7. NEDO-10527, Supplement 1, Rod Drop Accident Analysis For Large Boiling Water Reactors, Addendum No. 1, Multiple Enrichment Cores With Axial Gadolinium, July 1972.

(continued)

BASES

REFERENCES (continued)

8. NEDO-10527, Supplement 2, Rod Drop Accident Analysis For Large Boiling Water Reactors, Addendum No. 2, Exposed Cores, January 1973.

9. NEDO-21778-A, Transient Pressure Rises Affecting Fracture Toughness Requirements For Boiling Water Reactors, December 1978.

10. ASME, Boiler and Pressure Vessel Code, Section III, 1965 Edition, Addenda Winter of 1966.

11. NEDO-21231, Banked Position Withdrawal Sequence, January 1977.

12. 10 CFR 50.36(c)(2)(ii).

13. NEDO-33091-A, Revision 2, Improved BPWS Control Rod Insertion Process, July 2004.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Standby Liquid Control (SLC) System

BASES

BACKGROUND

The SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive, xenon free state without taking credit for control rod movement. The SLC System satisfies the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram.

The SLC System consists of a boron solution storage tank, two positive displacement pumps, two explosive valves that are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged near the bottom of the core shroud, where it then mixes with the cooling water rising through the core. A smaller tank containing demineralized water is provided for testing purposes.

APPLICABLE SAFETY ANALYSIS

The SLC System is manually initiated from the main control room, as directed by the emergency operating procedures, if the operator believes the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that enough control rods cannot be inserted to accomplish shutdown and cooldown in the normal manner. The SLC System injects borated water into the reactor core to add negative reactivity to compensate for all of the various reactivity effects that could occur during plant operations. To meet this objective, it is necessary to inject a quantity of boron, which produces a concentration of 660 ppm of equivalent natural boron, in the reactor coolant at 70°F. To allow for potential leakage and imperfect mixing in the reactor system, an amount of boron equal to 125% of the amount cited above is injected (Ref. 2). The volume versus concentration limits in Figure 3.1.7-1 and the concentration versus temperature limits in Figure 3.1.7-2 are calculated such that the required concentration is achieved accounting for dilution in the RPV with normal water level and including the water volume in the residual heat removal shutdown cooling piping and in the recirculation loop piping. This quantity of borated solution is the amount that is above the pump suction level in the boron solution storage tank (6 inches above tank bottom). No credit is taken for the portion of the

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

tank volume that cannot be injected.

Post-accident operation of the SLC System is also required to maintain the suppression pool pH above 7 so the re-evolution of iodine from the pool does not occur.

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

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control independent of normal reactivity control provisions provided by the control rods. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE; each contains an OPERABLE pump, an explosive valve, and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate controls to ensure that the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE when only a single control rod can be withdrawn.

In Modes 1, 2, and 3 operation of the SLC System is required to maintain suppression pool pH above 7 to prevent iodine re-evolution from the pool.

ACTIONS

A.1

If one SLC subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the shutdown function. However, the overall reliability is reduced because a single failure in the remaining OPERABLE subsystem could result in reduced SLC System shutdown capability. The 7 day Completion Time

(continued)

BASES

ACTIONS

A.1 (continued)

is based on the availability of an OPERABLE subsystem capable of performing the intended SLC System function and the low probability of a Design Basis Accident (DBA) or severe transient occurring concurrent with the failure of the control rods to shut down the reactor.

B.1

If both SLC subsystems are inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of a DBA or severe transient occurring concurrent with the failure of the control rods to shut down the reactor.

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 does not apply. To achieve this status, the plant must be brought to MODE 4 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 3.1.7.1, SR 3.1.7.2, and SR 3.1.7.3

SR 3.1.7.1 through SR 3.1.7.3 verify certain characteristics of the SLC System (e.g., the volume and temperature of the borated solution in the storage tank), thereby ensuring SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure that the proper borated solution volume and temperature, including the temperature of the pump suction piping, are maintained. Maintaining a minimum specified borated solution temperature is important in ensuring that the boron remains in solution and does not precipitate out in the storage tank or in the pump suction piping. The temperature versus concentration curve of Figure 3.1.7-2 ensures that a 10°F margin will be maintained above the saturation temperature. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.4 and SR 3.1.7.6

SR 3.1.7.4 verifies the continuity of the explosive charges in the injection valves to ensure that proper operation will occur if required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.7.6 verifies that each valve in the system is in its correct position, but does not apply to the squib (i.e., explosive) valves. Verifying the correct alignment for manual valves in the SLC System flow path provides assurance that the proper flow paths will exist for system operation. A valve is also allowed to be in the non-accident position provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve control. This is acceptable since the SLC System is a manually initiated system. This Surveillance does not apply to valves that are locked, sealed, or otherwise secured in position since they are verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.7.5

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure that the proper concentration of boron in the storage tank is maintained per Figure 3.1.7-1. SR 3.1.7.5 must be performed anytime boron or water is added to the storage tank solution to determine that the boron solution concentration is within the specified limits. SR 3.1.7.5 must also be performed anytime the temperature is restored to within the limits of Figure 3.1.7-2, to ensure that no significant boron precipitation occurred. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.7.7

Demonstrating that each SLC System pump develops a flow rate ≥ 50 gpm at a discharge pressure ≥ 1275 psig by recirculating demineralized water to the test tank ensures that pump performance has not degraded during the surveillance interval. This minimum

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.7 (continued)

pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms pump and motor capability and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program.

SR 3.1.7.8 and SR 3.1.7.9

These Surveillances ensure that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve primer assembly. The replacement primer assembly for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the sodium pentaborate solution. An acceptable method for verifying that the suction piping is unblocked is to manually initiate the system, except the explosive valves, and pump from the storage tank and recirculating it back to the storage tank. Upon completion of this verification, the pump suction piping must be flushed with demineralized water to ensure piping between the storage tank and pump suction is unblocked.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This is especially true in light of the temperature verification of this piping required by SR 3.1.7.3. However, if, in performing SR 3.1.7.3, it is determined that the temperature of this piping has fallen below the specified minimum, SR 3.1.7.9 must be performed once within 24 hours after the piping temperature is restored to within the limits of Figure 3.1.7-2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.10

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic tests on the granular sodium pentaborate to verify the actual B-10 enrichment must be performed prior to addition to the SLC tank in order to ensure that the proper B-10 atom percentage is being used. A single isotopic test from a single batch can suffice as the required analysis for any number of mixings and additions from this batch. Certified vendor analytical test results may be used to satisfy this requirement.

SR 3.1.7.11

The B-10 enrichment of boron in solution in the SLC tank is only affected by the B-10 enrichment of tank additions. The requirements of SR 3.1.7.10 serve to assure that tank additions contain the proper enrichment. SR 3.1.7.11 requires periodic verification of the B-10 enrichment of the solution in the SLC tank, providing added assurance that the proper B-10 enrichment is maintained. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program

REFERENCES

1 10 CFR 50.62.

2 UFSAR, Section 3.9.4.

3 10 CFR 50.36(c)(2)(ii).

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 (each SDV consisting of a header and an instrument volume), each receiving approximately one half of the control rod drive (CRD) discharges. Each instrument volume has a drain line each having two valves in series for a total of four drain valves. Each header is connected to a separate vent line each having two valves in series for a total of four vent valves. 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 doses remain within the limits of 10 CFR 100 (Ref. 2); 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 doses are well within the limits of 10 CFR 100 (Ref. 2), and adequate core cooling is maintained (Ref. 3). The SDV vent and drain valves allow continuous drainage of the SDV during normal plant operation to ensure that the SDV has sufficient capacity to contain the reactor coolant discharge during a full core scram. To

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 10 CFR 50.36(c)(2)(ii) (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. 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 since the reactor mode switch is in shutdown and a control rod block is applied. 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 a Note indicating that a separate Condition entry is allowed for each SDV vent and drain line. This is acceptable, since the Required Actions 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 an 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

(continued)

BASES

ACTIONS (continued)

line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, 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 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 lines are 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 met, 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 the 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 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1 (continued)

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 Frequency is in accordance with the Inservice Testing Program requirements.

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 30 seconds after receipt of a scram signal is based on the bounding leakage case evaluated in the accident analysis (Ref. 3). 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 3.5.5.2.

2. 10 CFR 100.

3. NUREG-0803, Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping, August 1981.

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

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 the peak cladding temperature (PCT) during the postulated design basis loss of coolant accident (LOCA) does not exceed limits specified in 10 CFR 50.46.
APPLICABLE SAFETY ANALYSES	The analytical methods and assumptions used in evaluating the fuel design limits are presented in Reference 1. The analytical methods and assumptions used in evaluating the Design Basis Accident (DBA) that determines the APLHGR limits are presented in References 1, 3, 4, 5, 6, and 7. APLHGR limits are equivalent to the assumed APLHGR in the LOCA analysis or the LHGR design limit (assuming a 1.0 local peaking factor) whichever is less. APLHGR limits are developed as a function of exposure for each fuel bundle design (Refs. 5 and 6). LOCA analyses are then performed to ensure that the above determined APLHGR limits are adequate to meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A complete discussion of the analysis code is provided in Reference 7. 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 an assembly. A conservative multiplier is applied to the LHGR assumed in the LOCA analysis to account for the uncertainty associated with the measurement of the APLHGR. For single recirculation loop operation, a conservative multiplier is applied to the exposure dependent APLHGR limits for two loop operation (Ref. 5). This maximum limit is due to the conservative analysis assumption of an earlier departure from nucleate boiling with one recirculation loop available, resulting in a more severe cladding heatup during a LOCA. The APLHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 8).
LCO	The APLHGR limits specified in the COLR are the result of the fuel design and DBA analyses. With only one recirculation loop in operation, in conformance with the requirements of LCO 3.4.1, “Recirculation Loops Operating,” the limit is determined by multiplying the exposure dependent APLHGR limit by a conservative multiplier determined by a specific single recirculation loop analysis (Ref. 5).

(Continued)

BASES

APPLICABILITY

The APLHGR limits are primarily derived from fuel design evaluations and analysis of LOCAs 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. This trend continues down to the power range of 5% to 15% RTP when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor scram function provides prompt scram initiation during any significant transient, thereby effectively removing any APLHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels <25% 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 and transient analyses 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 and within design limits of the fuel rods. 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 transient or DBA occurring simultaneously with the APLHGR out of specification.

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 <25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to <25% 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 12 hours after THERMAL POWER is ≥ 25% RTP and then periodically thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(Continued)

BASES

REFERENCES

1. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, (Revision specified in the COLR).

2. UFSAR, Chapter 3.

3. UFSAR, Chapter 6.

4. UFSAR, Chapter 14.

5. Supplemental Reload Licensing Report for James A. FitzPatrick (Revision specified in the COLR).

6. JAF-RPT-08-00014 R0, James A. FitzPatrick Nuclear Power Plant GNF2 ECCS-LOCA Evaluation, August 2008.

7. NEDC-31317P, Revision 2, James A. FitzPatrick Nuclear Power Plant SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, April 1993.

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

9. NEDC-33087P, Revision 1, J.A. FitzPatrick Nuclear Power Plant APRM/RBM/Technical Specifications / Maximum Extended Operating Domain (ARTS/MEOD), September 2005.

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 operating limit MCPR is established to ensure that no fuel damage results during abnormal operational transients, and that 99.9% of the fuel rods are not susceptible to boiling transition if the limit is not violated. 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 ANALYSIS

The analytical methods and assumptions used in evaluating the abnormal operational transients to establish the operating limit MCPR are presented in References 2, 3, 4, 5, 6, 7, 8, 9 and 11. To ensure that the MCPR Safety Limit (SL) is not exceeded during any transient that occurs with moderate frequency, limiting transients are analyzed either with TRACG or other NRC-approved methodologies. The types of transients evaluated are loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature increase. The TRACG methodology calculates an operating limit MCPR (OLMCPR) for the transient initial condition that will result in no more than 0.1% of the fuel rods susceptible to boiling transition. The other methodologies calculate a reduction in CPR for each transient, with the largest change in CPR (delta-CPR) resulting from the limiting transient. When the largest delta-CPR is combined with the MCPR (99.9%), an OLMCPR is obtained. The OLMCPR, calculated by either the TRACG or other methodology, sets the core operating limits.

MCPR (99.9%) is determined to ensure more than 99.9% of the fuel rods in the core are not susceptible to boiling transition using a

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved Critical Power correlations. Details of the MCPR (99.9%) calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties and the nominal values of the parameters used in the MCPR (99.9%) statistical analysis.

The MCPR operating limits are derived from the MCPR (99.9%) value and the transient analysis, and are dependent on the operating core flow and core exposure to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Refs. 6, 7, 8, and 9). A generator load reject without bypass and a feedwater controller transient normally result in the worst case MCPR transients for a given fuel cycle.

Flow-dependent MCPR limits, MCPR(F), are necessary to assure that the MCPR SL is not violated during recirculation flow increase events. The design basis flow increase event is a slow-flow power increase event which is not terminated by scram, but which stabilizes at a new core power corresponding to the maximum possible core flow. Flow runout events were analyzed along a constant xenon flow control line assuming a quasi steady-state plant heat balance. The MCPR(F) limit is specified as an absolute value and is generic and cycle-independent. The operating limit is dependent on the maximum setting of the scoop tube in the Recirculation Flow Control System.

Above the power at which the scram is bypassed (P_{Bypass}), bounding power-dependent trend functions have been developed. This trend function, Kp, is used as a multiplier to the rated MCPR operating limits to obtain the power-dependent MCPR limits, MCPR(P). Below the power at which the scram is automatically bypassed (Below P_{Bypass}), the MCPR(P) limits are actual absolute operating limit MCPR values, rather than multipliers on the rated power operating limit MCPR.

The MCPR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 10).

LCO

The MCPR operating limits specified in the COLR (MCPR (99.9%) value, MCPR(F) values, and MCPR(P) values) are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is a function of exposure, control rod scram times and core flow. The MCPR values for each fuel assembly must remain above the operating limit MCPR. The operating limit MCPR is

(continued)

BASES

LCO (continued)

determined by the larger of the MCPR(F) and MCPR(P) limits, which are based on the MCPR (99.9%) limit specified in the COLR.

APPLICABILITY

The MCPR operating limits are primarily derived from the analyses of transients that are assumed to occur at high power levels. Below 25% RTP, the reactor is operating at a minimum recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 25% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs. Statistical analyses indicate that the nominal value of the initial MCPR expected at 25% RTP is > 3.5.

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 actual values for key plant parameters 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 25% 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 < 25% 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 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.

(continued)

BASES

ACTIONS (continued)

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 < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% 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 12 hours after THERMAL POWER is ≥ 25% RTP and then periodically thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. SR 3.2.2.2 determines the value of τ, which is a measure of the actual scram speed distribution compared with the assumed distribution. The MCPR operating limit is then determined based on an interpolation between the applicable limits for Option A (scram times of LCO 3.1.4, "Control Rod Scram Times") and Option B (realistic scram times) analyses. The parameter τ 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, and SR 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in τ expected during the fuel cycle.

(continued)

BASES (continued)

REFERENCES

1 NUREG-0562, Fuel Rod Failure as a Consequence of Departure From Nucleate Boiling or Dry Out, June 1979.

2 NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, (Revision specified in the COLR).

3 UFSAR, Chapter 3.

4 UFSAR, Chapter 6.

5 UFSAR, Chapter 14.

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

7 NEDC-33087P, Revision 1, J.A. FitzPatrick Nuclear Power Plant APRM/RBM/Technical Specifications / Maximum Extended Operating Domain (ARTS/MEOD), September 2005.

8 NEDC-32016P-1, Power Uprate Safety Analysis for James A. FitzPatrick Nuclear Power Plant, April 1993, including Errata and Addenda Sheet No. 1, dated January 1994.

9 Supplemental Reload Licensing Report for James A. FitzPatrick (Revision specified in the COLR).

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

11 ECH-NE-16-00030, J.A. FitzPatrick Nuclear Power Plant TRACG Implementation for Reload Licensing Transient Analysis (T1309), EC-67256.

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, including abnormal operational transients. 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 anticipated operating conditions identified in Reference 1.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel system design are presented in Reference 2. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection systems) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR Parts 20, 50, and 100. The mechanisms that could cause fuel damage during abnormal 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. 2).

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. The analysis also includes allowances for short term

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

transient operation above the operating limit to account for abnormal operational transients, plus an allowance for densification power spiking.

LHGR is the fuel rod power at any axial location as a function of peak pellet exposure in the rod segment. Limits are provided by fuel type.

LHGR is an input to the LOCA analysis. APLHGR limits are chosen based on the LHGR limit for the fuel type. During single loop operation (SLO) the APLHGR limit is multiplied by an SLO multiplier due to the conservative analysis assumption of an earlier departure from nucleate boiling in SLO. An SLO LHGR multiplier is also required to be consistent with the ECCS SLO analysis (Ref. 4).

LHGR limits are developed as a function of exposure and the various operating core flow and power states to ensure adherence to fuel design limits during the limiting abnormal operational transients (Ref. 5 and 7). Flow dependent LHGR limits protect the fuel against the effects of slow flow runout transients. The flow dependent multiplier, LHGRFAC(F), is dependent on the maximum runout core flow. The maximum runout core flow is dependent on the existing setting of the scoop tube in the Recirculation Flow Control System.

Power dependent multipliers, LHGRFAC(P), are also generated based on analyses of limiting plant transients (other than core flow increases) over a range of power and flow conditions. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which turbine stop valve closure and turbine control valve fast closure scram trips are bypassed, both high and low core flow LHGRFAC(P) limits are provided for operation at power levels between 25% RTP and the previously mentioned bypass power level. LHGR limits are reduced by LHGRFAC(P) and LHGRFAC(F) at various operating conditions to ensure that all fuel design criteria are met for normal operation and abnormal operational transients.

The LHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

(continued)

BASES (continued)

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.

The LHGR limits specified in the COLR are the result of the fuel design and transient analyses. For two recirculation loops operating, the limit is determined by multiplying the smaller of the LHGRFAC(P) and LHGRFAC(F) factors times the exposure dependent LHGR limits. With only one recirculation loop in operation, the limit is determined by multiplying the exposure dependent LHGR limit by the smaller of either LHGRFAC(P), LHGRFAC(F), or the LHGR SLO multiplier as determined by a specific single recirculation loop analysis (Ref. 6).

APPLICABILITY

The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 25% 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 ≥ 25% 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.

(continued)

BASES

ACTIONS (continued)

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 < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER TO < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The LHGR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and periodically thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.5.

2. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, (Revision specified in the COLR).

3. 10 CFR 50.36(c)(2)(ii).

4. SC03-12, ECCS Single Loop Operation MAPLHGR and LHGR Multipliers, dated July 17, 2003.

5. NEDC-33087P, Revision 1, J.A. FitzPatrick Nuclear Power Plant APRM/RBM/Technical Specifications / Maximum Extended Operating Domain (ARTS/MEOD), September 2005.

6. Supplemental Reload Licensing Report for James A. FitzPatrick (Revision specified in the COLR).

7. ECH-NE-16-00030, J.A. FitzPatrick Nuclear Power Plant TRACG Implementation for Reload Licensing Transient Analysis (T1309), EC67256

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 pressure boundary (RCPB) 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.

Technical Specifications are required by 10 CFR 50.36 to contain LSSS defined by the regulation as "...settings for automatic protective devices...so chosen that automatic protective action will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytic Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytic Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective devices must be chosen to be more conservative than the Analytic Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The Trip Setpoint is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytic Limit and thus ensuring the SL would not be exceeded. As such, the Trip Setpoint accounts for uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., repeatability), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the Trip Setpoint plays an important role in ensuring that SLs are not exceeded. As such, the Trip Setpoint meets the definition of an LSSS and could be used to meet the requirement that they be contained in the Technical Specifications.

(continued)

BASES

BACKGROUND (continued)

Technical Specifications contain values related to the OPERABILITY of equipment required for the safe operation of the facility. Operable is defined in Technical Specifications as ".being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and therefore the LSSS as defined by 10 CFR 50.36 is the same as the OPERABILITY limit for those devices. However, use of the Trip Setpoint to define OPERABILITY in Technical Specifications and its corresponding designation as the LSSS required by 10 CFR 50.36 would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protective device setting during a surveillance. This would result in Technical Specification compliance problems, as well as reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protective device with a setting that has been found to be different from the Trip Setpoint due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the Trip Setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the device to the Trip Setpoint to account for further drift during the next surveillance interval.

Use of the Trip Setpoint to define "as found" OPERABILITY and its designation as the LSSS under the expected circumstances described above would result in actions required by both the rule and Technical Specifications that are clearly not warranted. However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the Technical Specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value which, as stated above, is the same as the LSSS. The Allowable Values specified in Table 3.3.1.1-1 serve as the LSSS such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value. As such, the Allowable Value differs from the Trip Setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a Safety Limit is not exceeded at any given point of time as long as the device has not drifted beyond that

(continued)

BASES

BACKGROUND (continued)

expected during the surveillance interval. If the actual setting of the device is found to have exceeded the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required. Note that, although the channel is "OPERABLE" under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowance of the uncertainty terms assigned.

The RPS, as described in the UFSAR, Section 7.2 (Ref. 1), includes sensors, relays, logic circuits, 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, EHC Oil Pressure-Low, 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 position and manual scram signals). Most channels include instrumentation that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs an RPS trip signal to the trip logic.

The RPS is comprised of two independent trip systems (A and B) with three trip channels in each trip system (trip channels A1, A2, and A3, B1, B2, and B3) as described in Reference 1. Trip channels A1, A2, B1, and B2 contain automatic protective instrument logic. The above monitored parameters are represented by at least one input to each of these automatic trip channels. The outputs of the automatic trip 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. There are four RPS channel test switches, one associated with each of the four automatic trip channels. These test switches allow the operator to test the OPERABILITY of the individual trip channel automatic scram contactors. In addition, trip channels A3 and B3 (one trip channel per trip system)

(continued)

BASES

BACKGROUND (continued)

are provided for manual scram. Placing the reactor mode switch in shutdown position or depressing both channel push buttons (one per trip system) will initiate the manual trip function. Each trip system is 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 approximately 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed.

Two scram pilot valves are located in the hydraulic control unit for each control rod drive (CRD). Each scram pilot valve is solenoid 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 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 ANALYSIS, LCO, and APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 1, 2, and 3. The RPS is required to initiate a reactor scram when monitored parameter values exceed 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 RCPB, and the containment by minimizing the energy that must be absorbed following a LOCA.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

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, where appropriate.

Allowable Values are specified, as appropriate, for RPS Functions 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 exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis or other appropriate documents. The trip setpoints are derived from the analytic limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in

harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

The 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 or other conditions 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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

signals.

The only MODES specified in Table 3.3.1.1-1 are MODES 1 and 2 and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. No RPS Function is required in MODES 3 and 4, since 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. In MODE 5, 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, no RPS function is 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.

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 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. 2). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, a generic analysis has 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 enthalpy 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

The IRM System is divided into two groups of IRM channels, 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 the IRM Allowable Value of 120 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 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, the RWM, and Rod Block Monitor provide protection against control rod withdrawal error events and the IRMs are not required. The IRMs are automatically bypassed when the reactor mode selector 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. If an IRM Operate-Calibrate switch is moved to any position other than "Operate," the detector voltage drops below a preset level, or 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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

1.b. Intermediate Range Monitor—Inop (continued)

Allowable Value for this Function.

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

Average Power Range Monitor

2.a. Average Power Range Monitor Neutron Flux—High (Startup)

The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core that 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. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux—High (Startup) 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 (Startup) 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 (Startup) Function will provide the primary trip signal for a core-wide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux—High (Startup) Function. However, this Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 25% 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 < 25% RTP.

The APRM System is divided into two groups of channels with three APRM channels providing input to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux—High (Startup) with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux—High (Startup) (continued)

four axial levels at which the LPRMs are located.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

The Average Power Range Monitor Neutron Flux—High (Startup) 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 (Fixed) Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events. The APRM Neutron Flux—High (Startup) Function is bypassed when the reactor mode switch is in the run position.

2.b. Average Power Range Monitor Neutron Flux—High (Flow Biased)

The Average Power Range Monitor Neutron Flux—High (Flow Biased) Function monitors neutron flux and approximates the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux trip level is varied as a function of recirculation drive flow but is clamped at an upper limit that is lower than the Average Power Range Monitor Neutron Flux—High (Fixed) Function, Function 2.c, Allowable Value. The Average Power Range Monitor Neutron Flux—High (Flow Biased) Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event), however, no credit is taken for this Function in the safety analyses except in the case of the thermal-hydraulic instability analysis. This protection is primarily achieved by the clamped portion of the Allowable Value. The APRM Neutron Flux—High (Flow Biased) Function will suppress power oscillations prior to exceeding the fuel safety limit (MCPR) caused by thermal hydraulic instability. As described in References 5 and 6, this protection is provided at a high statistical confidence level for core-wide mode oscillations and at a nominal statistical confidence level for regional mode oscillations. References 5 and 6 also show that the core-wide mode of oscillation is more likely to occur due to the large single-phase channel pressure drop associated with the small fuel inlet orifice diameters. This protection for power oscillations is achieved by that portion of the Allowable Value which varies as a function of the recirculation drive flow.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Neutron Flux—High (Flow Biased) (continued)

The APRM System is divided into two groups of channels with three APRM channels providing input to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux—High (Flow Biased) 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 failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located. Each APRM channel receives two independent, redundant flow signals representative of total recirculation loop flow. The recirculation loop flow signals are generated by four flow units, two of which supply signals to the trip system A APRMs, while the other two supply signals to the trip system B APRMs. Each flow unit signal is provided by summing up the flow signals from the two recirculation loops. To obtain the most conservative reference signals, the total flow signals from the two flow units (associated with a trip system as described above) are routed to a low auction circuit associated with each APRM. Each APRM's auction circuit selects the lower of the two flow unit signals for use as the scram trip reference for that particular APRM. Each required Average Power Range Monitor Neutron Flux—High (Flow Biased) channel requires an input from one OPERABLE flow unit, since the individual APRM channel will perform the intended function with only one OPERABLE flow unit input. However, in order to maintain single failure capability for the Function, at least one required Average Power Range Monitor Neutron Flux—High (Flow Biased) channel in each trip system must be capable of maintaining an OPERABLE flow unit signal in the event of a failure of an auction circuit, or a flow unit, in the associated trip system (e.g., if a flow unit is inoperable, one of the two required Average Power Range Monitor Neutron Flux—High (Flow Biased) channels in the associated trip system must be considered inoperable).

The flow biased Allowable Value is credited in the safety analyses (thermal-hydraulic instability) and is specifically confirmed for each operating cycle. For this reason the Allowable Value is included in the COLR for both single and two recirculation loop operation. The clamped

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Neutron Flux—High (Flow Biased) (continued)

portion of the Allowable Value is set more conservative than the APRM Neutron Flux—High (Fixed) (Function 2.c).

The Average Power Range Monitor Neutron Flux—High (Flow Biased) 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 (Fixed)

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Neutron Flux—High (Fixed) Function is capable of generating a trip signal to prevent fuel damage or excessive Reactor Coolant System (RCS) pressure. For the overpressurization protection analysis of Reference 7, the Average Power Range Monitor Neutron Flux—High (Fixed) Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 8) takes credit for the Average Power Range Monitor Neutron Flux—High (Fixed) Function to terminate the CRDA.

The APRM System is divided into two groups of channels with three APRM channels providing input to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux—High (Fixed) 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 failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

The Average Power Range Monitor Neutron Flux—High (Fixed) 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 (Fixed) Function is assumed in the CRDA analysis (Ref. 8), which is applicable in MODE 2, the Average Power Range Monitor Neutron Flux—High (Startup) 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 (Fixed) Function is not required in MODE 2.

2.d. Average Power Range Monitor—Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM Operate-Calibrate switch is moved to any position other than "Operate," an APRM module is unplugged, or the APRM has too few LPRM inputs (< 11), an inoperative trip signal will be received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each 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.

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

There is no Allowable Value for this Function. This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

3. Reactor Pressure—High

An increase in the RCS 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. The Reactor Pressure—High Function is

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3. Reactor Pressure — High (continued)

specifically credited in the safety analyses for the generator load reject and turbine trip events when initiated from low power levels (Refs. 9 and 10). At low power levels (e.g., below 29% RTP), the Turbine Stop Valve — Closure and Turbine Control Valve Fast Closure, EHC Oil Pressure — Low Functions are not required to be OPERABLE. For the overpressurization protection analysis of Reference 7, reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Neutron Flux — High (Fixed) signal, not the Reactor Pressure — High signal), along with the S/RVs, limits the peak Reactor Pressure Vessel (RPV) pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Pressure — High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during pressurization events.

Four channels of Reactor 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.

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 one of the Functions assumed in the analysis of the recirculation line break (Ref. 11). 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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

4. Reactor Vessel Water Level — Low (Level 3) (continued)

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 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 Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 12).

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.

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 7, the Average Power Range Monitor Neutron Flux — High (Fixed) 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 References 13 and 14 (i.e., failure of the pressure regulator and manual closure of MSIVs, respectively) and in the main steam line break accident analyzed in Reference 15.

The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

5. Main Steam Isolation Valve—Closure (continued)

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 design permits closure of any two lines without a full scram being initiated.

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 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 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 MODE 2, the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection.

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 to scram the reactor for LOCAs inside primary containment (Ref. 11). 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.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

6. Drywell Pressure—High (continued)

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 SDVs, east and west, are independent with separate drain lines and isolation valves. Each SDV accommodates approximately half of the water displaced by the motion of the CRD pistons during a reactor scram. Should either SDV 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 volumes are 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 UFSAR. However, they are retained to ensure the RPS remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs (instrument volume portions of the SDVs) is measured by two float type level switches and two differential pressure transmitters for a total of eight level signals. The outputs of these devices are arranged so that there are either two level switch signals or two differential pressure transmitter signals to each RPS trip channel. Each trip channel receives signals from instrumentation from both the east and west SDVs and each RPS trip system receives signals from the two diverse methods. The level measurement instrumentation satisfies the recommendations of Reference 16.

The Allowable Value is chosen low enough to ensure that there is sufficient volume in each SDV to accommodate the water directed to it 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 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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

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 the heat sink and 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 (Ref. 10) and feedwater controller failure—maximum demand (Ref. 17) events. For these events, the reactor scram reduces the amount of energy required to be absorbed and 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. One double pole (contact) position switch is associated with each stop valve. One of the two contacts 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 contact inputting to a relay. The relay contacts provide a parallel logic input to an RPS trip channel. 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 ≥ 29% RTP as measured by turbine first stage pressure. This is accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut (except during required testing or upon actual demand) at THERMAL POWER ≥ 29% RTP. In addition, other steam loads, such as second stage reheaters in operation, must be accounted for in establishing the setpoint for turbine first stage pressure. Otherwise, the setpoint would be non-conservative with respect to the 29% RTP RPS bypass.

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

Eight channels of Turbine Stop Valve—Closure Function, with four

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

8. Turbine Stop Valve—Closure (continued)

channels in each trip system, are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function even if one TSV should fail to close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ 29% RTP. This Function is not required when THERMAL POWER is < 29% RTP since the Reactor Pressure—High and the Average Power Range Monitor Neutron Flux—High (Fixed) Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, EHC Oil Pressure—Low

Fast closure of the TCVs results in the loss of the heat sink and 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, EHC Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 9. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, EHC Oil Pressure—Low signals are initiated by low electrohydraulic control (EHC) fluid pressure in the emergency trip header, between the fast closure solenoid and the disc dump valve for each control valve. One pressure switch is associated with each control valve, and the signal from each switch is assigned to a separate RPS trip channel. This Function must be enabled at THERMAL POWER ≥ 29% RTP as measured by turbine first stage pressure. This is accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut (except during required testing or upon actual demand) at THERMAL POWER ≥ 29% RTP. In addition, other steam loads, such as second stage reheaters in operation, must be accounted for in establishing the setpoint for turbine first stage pressure. Otherwise, the setpoint would be non-conservative with respect to the 29% RTP RPS bypass.

The Turbine Control Valve Fast Closure, EHC Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure and low enough to avoid inadvertent scrams.

Four channels of Turbine Control Valve Fast Closure, EHC Oil

(continued)

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

9. Turbine Control Valve Fast Closure, EHC Oil Pressure — Low (continued)

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 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 ≥ 29% RTP. This Function is not required when THERMAL POWER is < 29% RTP, since the Reactor Pressure — High and the Average Power Range Monitor Neutron Flux — High (Fixed) 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 trip channels, directly to the scram pilot valve solenoid power circuits. The manual scram trip channels 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 keylock four-position, four-bank switch. The reactor mode switch will scram the reactor if it is placed in the shutdown position. Scram signals from the reactor mode switch are input into each of the two RPS manual scram trip channels.

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

Two channels of Reactor Mode Switch — Shutdown Position Function, with one channel 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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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

11. Manual Scram

The Manual Scram push button channels provide signals, via the manual scram trip channels, directly to the scram pilot valve solenoid power circuits. These manual scram trip channels 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 two RPS manual scram trip channels. In order to cause a scram it is necessary that the channel in both manual scram trip systems 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.

Two channels of Manual Scram, with one channel in each manual scram trip system, 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

Note 1 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 unless specifically stated. Section 1.3 also specifies that the 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.

Note 2 has been provided to modify the ACTIONS for the RPS instrumentation functions of APRM Flow Biased Neutron-Flux High (Function 2.b) and APRM Fixed Neutron Flux-High (Function 2.c) when

(continued)

BASES

ACTIONS (continued)

they are inoperable due to failure of SR 3.3.1.1.2 and gain adjustments are necessary. Note 2 allows entry into associated Conditions and Required Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Condition entered and the Required Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

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 12 hours has been shown to be acceptable (Ref. 18) 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.

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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 18 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.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 18, 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.

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 and the IRM and

(continued)

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ACTIONS

C.1 (continued)

APRM Functions, 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).

For Functions 10 (Reactor Mode Switch—Shutdown Position) and 11 (Manual Scram) this would require both trip systems to have one channel 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.

E.1, F.1, and G.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 Action E.1 is consistent with the Completion Time provided in

(continued)

BASES

ACTIONS (continued)

H.1

LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)." 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.

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 second 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 (Ref. 18) assumption of the average time required to perform channel Surveillances. 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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.1 (continued)

verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. For Functions 8 and 9, this SR is associated with the enabling circuit sensing first stage pressure.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/- 2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). At ≥ 25% RTP, the Surveillance is required to have been satisfactorily performed in accordance with SR 3.0.2. A Note is provided which allows an increase

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.2 (continued)

in THERMAL POWER above 25% if the Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.3 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.4

A functional test of each automatic scram contactor is performed to ensure that each automatic RPS trip channel will perform the intended function. There are four RPS channel test switches, one associated with each of the four automatic trip channels (A1, A2, B1, and B2). These test switches allow the operator to test the OPERABILITY of the individual trip channel automatic scram contactors as an alternative to using an automatic scram function trip. This is accomplished by placing the RPS channel test switch in the test position, which will input a trip

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.4 (continued)

signal into the associated RPS trip channel. The RPS channel test switches are not specifically credited in the accident analysis. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. In accordance with Reference 18, the scram contactors must be tested as part of the Manual Scram Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.5 and SR 3.3.1.1.6

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. This is required prior to fully withdrawing SRMs since indication is being transitioned from the SRMs to the IRMs.

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, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block.

As noted, SR 3.3.1.1.6 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.5 and SR 3.3.1.1.6 (continued)

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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.7

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.8 and SR 3.3.1.1.11

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. For Function 2.b, the CHANNEL FUNCTIONAL TEST includes the adjustment of the APRM channel to conform to the calibrated flow signal. This ensures that the total loop drive flow signals from the flow units used to vary the setpoint is appropriately compared to a valid core flow signal to verify the flow signal trip setpoint and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. If the flow unit signal is not within the appropriate flow limit, one required APRM that receives an input from the inoperable flow unit must be declared inoperable. For Function 7.b, the CHANNEL FUNCTIONAL TEST is performed utilizing a water column or similar device to provide assurance that damage to a float or other portions of the float assembly will be detected. For Function 10, the CHANNEL FUNCTIONAL TEST is performed by actually placing the reactor mode switch in the shutdown position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. For Function 7.b, the CHANNEL CALIBRATION must be performed utilizing a water column or similar device to provide assurance that damage to a float or other portions of the float assembly will be detected. For Functions 8 and 9, SR 3.3.1.1.12 is associated with the enabling circuit sensing first stage turbine pressure as well as the trip function.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests in accordance with the Surveillance Frequency Control Program.

SR 3.3.1.1.9 has been modified by three Notes. Note 1 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 calorimetric calibration (SR 3.3.1.1.2) and the LPRM calibration against the TIPs (SR 3.3.1.1.7). A second Note is provided that requires the APRM and 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. Note 3 to SR 3.3.1.1.9 and the Note to SR 3.3.1.1.12 concerns the Neutron Flux—High (Flow Biased) Function (Function 2). Note 3 to SR 3.3.1.1.9 excludes the recirculation loop flow signal portion of the channel, since this portion of the channel is calibrated by SR 3.3.1.1.12. Similarly, the Note to SR 3.3.1.1.12 excludes all portions of the channel except the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.9 and SR 3.3.1.1.12 (continued)

recirculation loop flow signal portion, since they are covered by SR 3.3.1.1.9. Since the recirculation loop flow signal is also a portion of the Rod Block Monitor (RBM)—Upscale control rod block Function channels (Table 3.3.2.1-1, Control Rod Block Instrumentation, Function 1.a), satisfactory performance of SR 3.3.1.1.12 also results in satisfactory performance of SR 3.3.2.1.8 for the associated RBM—Upscale control rod block Function channels.

Reactor Pressure—High and Reactor Vessel Water Level—Low (Level 3) Function sensors (Functions 3 and 4, respectively) are excluded from the RPS RESPONSE TIME testing (Ref. 19). However, prior to the CHANNEL CALIBRATION of these sensors a response check must be performed to ensure adequate response. This testing is required by Reference 20. Personnel involved in this testing must have been trained in response to Reference 21 to ensure they are aware of the consequences of instrument response time degradation. This response check must be performed by placing a fast ramp or a step change into the input of each required sensor. The personnel, must monitor the input and output of the associated sensor so that simultaneous monitoring and verification may be accomplished.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.10

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology. For Functions 8 and 9, this SR is associated with the enabling circuit sensing first stage turbine pressure.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.13

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.14

This SR ensures that scrams initiated from the Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, EHC Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 29% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed during an inservice calibration at THERMAL POWER ≥ 29% RTP to ensure that the calibration is valid.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 29% 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, EHC 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.15

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 22.

RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. However, the sensors for Functions 3 and 4

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.15 (continued)

are excluded from specific RPS RESPONSE TIME measurement since the conditions of Reference 19 are satisfied. For Functions 3 and 4, sensor response time may be allocated based on either assumed design sensor response time or the manufacturer's stated design response time. For all other Functions, sensor response time must be measured.

Note 1 excludes neutron detectors from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 7.2.
2. UFSAR, Section 14.5.4.2.
3. NEDO-23842, Continuous Control Rod Withdrawal Transient In The Startup Range, April 18, 1978.
4. 10 CFR 50.36(c)(2)(ii).
5. NEDO-31960-A, BWR Owners' Group Long Term Stability Solutions Licensing Methodology, June 1991.
6. NEDO-31960-A, Supplement 1, BWR Owners' Group Long Term Stability Solutions Licensing Methodology, Supplement 1, March 1992.
7. UFSAR, Section 14.5.1.2.
8. UFSAR, Section 14.6.1.2.
9. UFSAR, Section 14.5.2.1.
10. UFSAR, Section 14.5.2.2.
11. UFSAR, Section 6.3.
12. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).
13. UFSAR, Section 14.5.5.1.
14. UFSAR, Section 14.5.2.3.

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BASES

REFERENCES (continued)

15. UFSAR, Section 14.6.1.5.

16. P. Check (NRC) letter to G. Lainas (NRC), BWR Scram Discharge System Safety Evaluation, December 1, 1980.

17. UFSAR, Section 14.5.9.

18. NEDC-30851P-A, Technical Specification Improvement Analyses for BWR Reactor Protection System, March 1988.

19. NEDO-32291-A System Analyses For the Elimination of Selected Response Time Testing Requirements, October 1995.

20. NRC letter dated October 28, 1996, Issuance of Amendment 235 to Facility Operating License DPR-59 for James A. FitzPatrick Nuclear Power Plant.

21. NRC Bulletin 90-01, Supplement 1, Loss of Fill-Oil in Transmitters Manufactured by Rosemount, December 1992.

22. UFSAR, Table 7.2-5.

23. GE-NE-0000-0006-7210-10, LPRM Calibration Interval Increase for James A. FitzPatrick Nuclear Power Plant, dated October 2002.

24. NRC Safety Evaluation for Technical Specification Amendment 277, dated May 1, 2003.

B 3.3 INSTRUMENTATION

B 3.3.1.2 Source Range Monitor (SRM) Instrumentation

BASES

BACKGROUND

The SRMs provide the operator with information relative to the neutron flux level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and determine when criticality is achieved. The SRMs are maintained fully inserted until the count rate is greater than a minimum allowed count rate (a control rod block is set at this condition). After SRM to intermediate range monitor (IRM) overlap is demonstrated (as required by SR 3.3.1.1.5), the SRMs are normally fully withdrawn from the core.

The SRM subsystem of the Neutron Monitoring System (NMS) consists of four channels. Each of the SRM channels can be bypassed, but only one at any given time, by the operation of a bypass switch. Each channel includes one detector that can be physically positioned in the core. Each detector assembly consists of a miniature fission chamber with associated cabling, signal conditioning equipment, and electronics associated with the various SRM functions. The signal conditioning equipment converts the current pulses from the fission chamber to analog DC currents that correspond to the count rate. Each channel also includes indication, alarm, and control rod blocks. However, this LCO specifies OPERABILITY requirements only for the monitoring and indication functions of the SRMs.

During refueling, shutdown, and low power operations, the primary indication of neutron flux levels is provided by the SRMs or special movable detectors connected to the normal SRM circuits. The SRMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low power operation is provided by LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"; LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"; IRM Neutron Flux – High and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Average Power Range Monitor (APRM) Neutron Flux-High, (Startup) Functions; and LCO 3.3.2.1, "Control Rod Block Instrumentation."

The SRMs have no safety function and are not assumed to function during any UFSAR design basis accident or transient analysis. However, the SRMs provide the only on-scale monitoring of neutron flux levels during startup and refueling. Therefore, they are being retained in Technical Specifications.

LCO

During startup in MODE 2, three of the four SRM channels are required to be OPERABLE to monitor the reactor flux level prior to and during control rod withdrawal, subcritical multiplication and reactor criticality, and neutron flux level and reactor period until the flux level is sufficient to maintain the IRMs on Range 3 or above. All but one of the channels are required in order to provide a representation of the overall core response during those periods when reactivity changes are occurring throughout the core.

In MODES 3 and 4, with the reactor shut down, two SRM channels provide redundant monitoring of flux levels in the core.

In MODE 5, during a spiral offload or reload, an SRM outside the fueled region will no longer be required to be OPERABLE, since it is not capable of monitoring neutron flux in the fueled region of the core. Thus, CORE ALTERATIONS are allowed in a quadrant with no OPERABLE SRM in an adjacent quadrant provided the Table 3.3.1.2-1, footnote (b), requirement that the bundles being spiral reloaded or spiral offloaded are all in a single fueled region containing at least one OPERABLE SRM is met. Spiral reloading and offloading encompass reloading or offloading a cell on the edge of a continuous fueled region (the cell can be reloaded or offloaded in any sequence).

In nonspiral routine operations, two SRMs are required to be OPERABLE to provide redundant monitoring of reactivity changes occurring in the reactor core. Because of the local nature of reactivity changes during refueling, adequate coverage is provided by requiring one SRM to be OPERABLE in the quadrant of the reactor core where CORE ALTERATIONS are being performed, and the other SRM to be OPERABLE in an adjacent quadrant containing fuel. These requirements ensure that the reactivity of the core will be continuously monitored during CORE ALTERATIONS.

(continued)

BASES

LCO (continued)

Special movable detectors, according to footnote (c) of Table 3.3.1.2-1, may be used in place of the normal SRM nuclear detectors. These special detectors must be connected to the normal SRM circuits in the NMS, such that the applicable neutron flux indication can be generated. These special detectors provide more flexibility in monitoring reactivity changes during fuel loading, since they can be positioned anywhere within the core during refueling. They must still meet the location requirements of SR 3.3.1.2.2 and all other required SRs for SRMs.

For an SRM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication.

APPLICABILITY

The SRMs are required to be OPERABLE in MODES 2, 3, 4, and 5 prior to the IRMs being on scale on Range 3 to provide for neutron monitoring. In MODE 1, the APRMs provide adequate monitoring of reactivity changes in the core; therefore, the SRMs are not required. In MODE 2, with IRMs on Range 3 or above, the IRMs provide adequate monitoring and the SRMs are not required.

ACTIONS

A.1 and B.1

In MODE 2, with the IRMs on Range 2 or below, SRMs provide the means of monitoring core reactivity and criticality. With any number of the required SRMs inoperable, the ability to monitor neutron flux is degraded. Therefore, a limited time is allowed to restore the inoperable channels to OPERABLE status.

Provided at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This time is reasonable because there is adequate capability remaining to monitor the core, there is limited risk of an event during this time, and there is sufficient time to take corrective actions to restore the required SRMs to OPERABLE status or to establish alternate IRM monitoring capability. During this time, control rod withdrawal and power increase is not precluded by this Required Action. Having the ability to monitor the core with at least one SRM, proceeding to IRM Range 3 or greater (with overlap required by SR 3.3.1.1.5), and thereby exiting the Applicability of this LCO, is acceptable for ensuring adequate core monitoring and allowing continued operation.

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

With three required SRMs inoperable, Required Action B.1 allows no positive changes in reactivity (control rod withdrawal must be immediately suspended) due to inability to monitor the changes. Required Action A.1 still applies and allows 4 hours to restore monitoring capability prior to requiring control rod insertion. This allowance is based on the limited risk of an event during this time, provided that no control rod withdrawals are allowed, and the desire to concentrate efforts on repair, rather than to immediately shut down, with no SRMs OPERABLE.

C.1

In MODE 2, if the required number of SRMs is not restored to OPERABLE status within the allowed Completion Time, the reactor shall be placed in MODE 3. With all control rods fully inserted, the core is in its least reactive state with the most margin to criticality. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 in an orderly manner and without challenging plant systems.

D.1 and D.2

With one or more required SRMs inoperable in MODE 3 or 4, the neutron flux monitoring capability is degraded or nonexistent. The requirement to fully insert all insertable control rods ensures that the reactor will be at its minimum reactivity level while no neutron monitoring capability is available. Placing the reactor mode switch in the shutdown position prevents subsequent control rod withdrawal by maintaining a control rod block. The allowed Completion Time of 1 hour is sufficient to accomplish the Required Action, and takes into account the low probability of an event requiring the SRM occurring during this interval.

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the ability to detect local reactivity changes in the core during refueling is degraded or nonexistent. CORE ALTERATIONS must be immediately suspended and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies.

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BASES

ACTIONS

E.1 and E.2 (continued)

Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity given that fuel is present in the core. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe, conservative position.

Action (once required to be initiated) to insert control rods must continue until all insertable rods in core cells containing one or more fuel assemblies are inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each SRM Applicable MODE or other specified conditions are found in the SRs column of Table 3.3.1.2-1.

SR 3.3.1.2.1 and SR 3.3.1.2.3

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 another channel. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.2

To provide adequate coverage of potential reactivity changes in the core when the fueled region encompasses more than one SRM, one SRM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed, and the other OPERABLE SRM must be in an adjacent quadrant containing fuel. Note 1 states that the SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 5 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRMs required to be OPERABLE for given CORE ALTERATIONS are, in fact, OPERABLE. In the event that only one SRM is required to be OPERABLE (when the fueled region encompasses only one SRM), per Table 3.3.1.2-1, footnote (b), only the a. portion of this SR is required. Note 2 clarifies that more than one of the three requirements can be met by the same OPERABLE SRM. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.2.4

This Surveillance consists of a verification of the SRM instrument readout to ensure that the SRM reading is greater than a specified minimum count rate with the detector full-in, which ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies loaded, the SRMs will not have a high enough count rate to satisfy the SR. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

To accomplish this, the SR is modified by a Note that states that the count rate is not required to be met on an SRM that has less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With four or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated core quadrant, even with a control rod withdrawn, the configuration will not be critical.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.4 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.2.5 and SR 3.3.1.2.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions. SR 3.3.1.2.5 is required in MODE 5, and ensures that the channels are OPERABLE while core reactivity changes could be in progress. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.2.6 is required in MODE 2 with IRMs on Range 2 or below, and in MODES 3 and 4. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Verification of the signal to noise ratio also ensures that the detectors are inserted to an acceptable operating level. In a fully withdrawn condition, the detectors are sufficiently removed from the fueled region of the core to essentially eliminate neutrons from reaching the detector. Any count rate obtained while the detectors are fully withdrawn is assumed to be "noise" only.

With few fuel assemblies loaded, the SRMs will not have a high enough count rate to determine the signal to noise ratio. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the conditions necessary to

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.5 and SR 3.3.1.2.6 (continued)

determine the signal to noise ratio. To accomplish this, SR 3.3.1.2.5 is modified by a Note that states that the determination of signal to noise ratio is not required to be met on an SRM that has less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With four or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated quadrant, even with a control rod withdrawn the configuration will not be critical.

The Note to SR 3.3.1.2.6 allows the Surveillance to be delayed until entry into the specified condition of the Applicability (THERMAL POWER decreased to IRM Range 2 or below). The SR must be performed within 12 hours after IRMs are on Range 2 or below. The allowance to enter the Applicability with the Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. Twelve hours is reasonable based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

SR 3.3.1.2.7

Performance of a CHANNEL CALIBRATION verifies the performance of the SRM monitors and associated circuitry. The Frequency considers the plant conditions required to perform the test, the ease of performing the test, and the likelihood of a change in the system or component status. The neutron detectors are excluded from the CHANNEL CALIBRATION (Note 1) because they cannot readily be adjusted. The detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life.

Note 2 to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.7 (continued)

Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. Twelve hours is reasonable based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

REFERENCES

None.

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

Control rods provide the primary means for control of reactivity changes. Control rod block instrumentation includes channel sensors, logic circuits, bypass circuits, switches, and relays that are designed to ensure that specified fuel design limits are not exceeded for postulated transients and accidents. During high power operation, the rod block monitor (RBM) may provide protection for control rod withdrawal error events. During low power operations, control rod blocks from the rod worth minimizer (RWM) enforce specific control rod sequences designed to mitigate the consequences of the control rod drop accident (CRDA). During shutdown conditions, control rod blocks from the Reactor Mode Switch–Shutdown Position Function ensure that all control rods remain inserted to prevent inadvertent criticalities.

The purpose of the RBM is to limit control rod withdrawal if localized neutron flux exceeds a predetermined setpoint during control rod manipulations. It is assumed to function to block further control rod withdrawal to preclude a MCPR Safety Limit (SL) violation. It is possible to set MCPR operating limits high enough that no single control rod withdrawal error (RWE) event would result in a MCPR SL violation. If the RBM is not assumed to function, the Allowable Value may be set for operating convenience. The RBM supplies a trip signal to the Reactor Manual Control System (RMCS) to appropriately inhibit control rod withdrawal during power operation above the low power range setpoint. The RBM has two channels, either of which can initiate a control rod block when the channel output exceeds the control rod block setpoint. One RBM channel inputs into one RMCS rod block circuit and the other RBM channel inputs into the second RMCS rod block circuit. The RBM channel signal is generated by averaging a set of local power range monitor (LPRM) signals. One RBM channel averages the signals of the LPRM detectors from the A and C level of the assigned LPRM assemblies, while the other RBM channel averages the signals of the LPRM detectors at the B and D level. Assignment of LPRM assemblies to be used in RBM averaging is controlled by the selection of control rods. If any LPRM detector assigned to an RBM is bypassed, the computed average signal is automatically adjusted to compensate for the number of LPRM input signals.

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BASES

BACKGROUND (continued)

The minimum number of LPRM inputs required for each RBM channel to prevent an instrument inoperative alarm is four when using four LPRM assemblies, three when using three LPRM assemblies, and two when using two LPRM assemblies. Each RBM also receives a recirculation loop flow signal. The RBM is automatically bypassed and the output set to zero if a peripheral rod is selected or the APRM used to normalize the RBM reading is < 30% RTP (Ref. 1). In addition, one of the two RBM channels can be manually bypassed.

When a control rod is selected, the gain of each RBM channel output is normalized to the assigned APRM channel. The assigned APRM channel is on the same RPS trip system as the RBM channel. The gain setting is held constant during the movement of the selected control rod to provide an indication of the change in the relative local power level. If the indicated local power level increases above the preset limit, a rod block will occur. The rod block setpoint line has an adjustable slope. The setpoint line provides a setpoint that is a function of the recirculation loop flow signal. The intercept of the setpoint line with rated recirculation loop flow is adjustable. In addition, to preclude rod movement with an inoperable RBM (if not bypassed), a downscale trip and an inoperable trip are provided. A rod block signal is generated if an RBM downscale trip or an inoperable trip occurs, since this could indicate a problem with the RBM channel. The downscale trip will occur if the RBM channel signal decreases below the downscale trip setpoint after the RBM channel signal has been normalized. The inoperable trip will occur during the nulling (normalization) sequence, if the RBM channel fails to null, too few LPRM inputs are available, a module is not plugged in, or the function switch is moved to any position other than "Operate".

The purpose of the RWM is to control rod patterns during startup and shutdown, such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount an rate of reactivity increase during a CRDA. Prescribed control rod sequences are stored in the RWM, which will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the stored

(continued)

BASES

BACKGROUND (continued)

sequence. The RWM determines the actual sequence based on position indication for each control rod. The RWM also uses steam flow signals compensated for steam pressure to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed (Ref. 2). The RWM is a single channel system that provides input into both RMCS rod block circuits.

The function of the individual rod sequence steps (banking steps) is to minimize the potential reactivity increase from postulated CRDA at low power levels. However, if the possibility for a control rod to drop can be eliminated, then the banking steps at low power levels are not needed to ensure the applicable event limits can not be exceeded. The rods may be inserted without the need to stop at intermediate positions since the possibility of a CRDA is eliminated by the confirmation that withdrawn control rods are coupled.

To eliminate the possibility of a CRDA, administrative controls require that any partially inserted control rods, which have not been confirmed to be coupled since their last withdrawal, be fully inserted prior to reaching the LPSP. If a control rod has been checked for coupling at notch 48 and the rod has since only been moved inward, this rod is in contact with its drive and is not required to be fully inserted prior to reaching the LPSP. However, if it cannot be confirmed that the control rod has only been moved inward, then that rod shall be fully inserted prior to reaching the LPSP. The remaining control rods may then be inserted without the need to stop at intermediate positions since the possibility of a CRDA has been eliminated.

With the reactor mode switch in the shutdown position, a control rod withdrawal block is applied to all control rods to ensure that the shutdown condition is maintained. This Function prevents inadvertent criticality as the result of a control rod withdrawal during MODE 3 or 4, or during MODE 5 when the reactor mode switch is required to be in the shutdown position. The reactor mode switch has two channels, each inputting into a separate RMCS rod block circuit. A rod block in either RMCS circuit will provide a control rod block to all control rods.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor

The RBM is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from an RWE event when it is assumed to function. The COLR provides details of cycle-specific assumptions of RBM operation. The analytical methods and assumptions used in evaluating the RWE event are summarized in Reference 3. A statistical analysis of RWE events was performed to determine the RBM response for both channels for each event. From these responses, the fuel thermal performance as a function of RBM Allowable Value was determined. The Allowable Values are chosen as a function of power level and flow. Based on the specified Allowable Values, operating limits are established.

The RBM Function satisfies Criterion 3 for cycles that credit the RBM in the RWE analysis or Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

Two channels of the RBM are required to be OPERABLE, with their setpoints within the appropriate Allowable Value specified in the COLR, to ensure that no single failure can preclude a rod block from this Function. The actual setpoints are calibrated consistent with applicable setpoint methodology.

Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values 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 power), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. When the RBM is assumed to function for MCPR SL protection, the analytic limits are derived from the limiting values of the process parameters obtained from the RWE safety analysis. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor (continued)

function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

The RBM may be assumed to mitigate the consequences of an RWE event when operating ≥ 30% RTP and a peripheral control rod is not selected. Below this power level, or if a peripheral control rod is selected, the consequences of an RWE event will not exceed the MCPR SL and, therefore, the RBM is not required to be OPERABLE (Ref. 1).

2. Rod Worth Minimizer

The RWM enforces the banked position withdrawal sequence (BPWS) to ensure that the initial conditions of the CRDA analysis are not violated. The analytical methods and assumptions used in evaluating the CRDA are summarized in Reference 5. The BPWS requires that control rods be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions. Requirements that the control rod sequence is in compliance with the BPWS are specified in LCO 3.1.6, "Rod Pattern Control."

When performing a shutdown of the plant, an optional BPWS control rod sequence (Ref. 10) may be used if the coupling of each withdrawn control rod has been confirmed. The rods may be inserted without the need to stop at intermediate positions. When using the Reference 10 control rod insertion sequence for shutdown, the RWM may be reprogrammed to enforce the requirements of the improved BPWS control rod insertion. Should the RWM become inoperable, the RWM may be bypassed and the improved BPWS shutdown sequence implemented under the controls in Condition D.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Rod Worth Minimizer (continued)

Since the RWM is a system designed to act as a backup to operator control of the rod sequences, only one channel of the RWM is available and required to be OPERABLE (Ref. 6). Special circumstances provided for in the Required Action of LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.6 may necessitate bypassing the RWM to allow continued operation with inoperable control rods, or to allow correction of a control rod pattern not in compliance with the BPWS. The RWM may be bypassed as required by these conditions, but then it must be considered inoperable and the Required Actions of this LCO followed.

Compliance with the BPWS, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is ≤ 10% RTP. When THERMAL POWER is > 10% RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Refs. 6 and 7). In MODES 3 and 4, all control rods are required to be inserted into the core; therefore, a CRDA cannot occur. In MODE 5, since only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical.

3. Reactor Mode Switch-Shutdown Position

During MODES 3 and 4, and during MODE 5 when the reactor mode switch is in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch-Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis.

The Reactor Mode Switch-Shutdown Position Function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

Two channels are required to be OPERABLE to ensure that no single failure will preclude a rod block when required. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

During shutdown conditions (MODE 3, 4, or 5), no positive

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Mode Switch-Shutdown Position (continued)

reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 5 with the reactor mode switch in the refueling position, the refuel position one-rod-out interlock (LCO 3.9.2 "Refuel Position One Rod-Out Interlock") provides the required control rod withdrawal blocks.

ACTIONS

A.1

With one RBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RBM. For this reason, Required Action A.1 requires restoration of the inoperable channel to OPERABLE status. The Completion Time of 24 hours is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel.

B.1

If Required Action A.1 is not met and the associated Completion Time has expired, the inoperable channel must be placed in trip within 1 hour. If both RBM channels are inoperable, the RBM is not capable of performing its intended function; thus, one channel must also be placed in trip. This initiates a control rod withdrawal block, thereby ensuring that the RBM function is met.

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

(continued)

BASES

ACTIONS (continued)

C.1, C.2.1.1, C.2.1.2, and C.2.2

With the RWM inoperable during a reactor startup, the operator is still capable of enforcing the prescribed control rod sequence. However, the overall reliability is reduced because a single operator error can result in violating the control rod sequence. Therefore, control rod movement must be immediately suspended except by scram. Alternatively, startup may continue if at least 12 control rods have already been withdrawn, or a reactor startup with an inoperable RWM during withdrawal of one or more of the first 12 control rods has not been performed in the current calendar year. These requirements minimize the number of reactor startups initiated with RWM inoperable. Required Actions C.2.1.1 and C.2.1.2 require verification of these conditions by review of plant logs and control room indications. Once Required Action C.2.1.1 or C.2.1.2 is satisfactorily completed, control rod withdrawal may proceed in accordance with the restrictions imposed by Required Action C.2.2. Required Action C.2.2 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (i.e., reactor engineer). Plant procedures prohibit this individual from having other concurrent duties during withdrawal or insertion.

The RWM may be bypassed under these conditions to allow continued operations. In addition, Required Actions of LCO 3.1.3 and LCO 3.1.6 may require bypassing the RWM, during which time the RWM must be considered inoperable with Condition C entered and its Required Actions taken.

D.1

With the RWM inoperable during a reactor shutdown, the operator is still capable of enforcing the prescribed control rod sequence. Required Action D.1 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (i.e., reactor engineer). The RWM may be bypassed under these conditions to allow the reactor shutdown to continue.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

With one Reactor Mode Switch—Shutdown Position control rod withdrawal block channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod withdrawal block function. However, since the Required Actions are consistent with the normal action of an OPERABLE Reactor Mode Switch—Shutdown Position Function (i.e., maintaining all control rods inserted), there is no distinction between having one or two channels inoperable.

In both cases (one or both channels inoperable), suspending all control rod withdrawal and initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies will ensure that the core is subcritical with adequate SDM, (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"). 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.

SURVEILLANCE REQUIREMENTS

As noted (Note 1) at the beginning of the SRs, the SRs for each Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are modified by Note 2 to indicate that when an RBM 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 control rod block 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. 8) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that a control rod block will be initiated when necessary.

SR 3.3.2.1.1

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the entire channel will perform the intended

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.1 (continued)

function. It includes the Reactor Manual Control Multiplexing System input. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions. Testing of the Reactor Manual Control Multiplexing System input shall include inputs of "no control rod selected," "peripheral control rod selected," and other control rods selected with two, three, or four LPRM assemblies around it. In addition, testing shall include a verification that an inoperable trip occurs when a module is not plugged in, or the function switch is moved to any position other than "Operate". The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the entire system will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions. The CHANNEL FUNCTIONAL TEST for the RWM is performed by attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2 and, SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. This allows entry into MODE 2 for SR 3.3.2.1.2, and entry into MODE 1 when THERMAL POWER is ≤ 10% RTP for SR 3.3.2.1.3, to perform the required Surveillance if the Frequency is not met per

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.2 and SR 3.3.2.1.3 (continued)

SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.4

The RBM is automatically bypassed when power is below a specified value or if a peripheral control rod is selected. The power level is determined from the APRM signals input to each RBM channel. The automatic bypass must be verified periodically to be < 30% RTP. In addition, it must also be verified that the RBM is not bypassed when a non-peripheral control rod is selected (only one non-peripheral control rod is required to be verified). If any bypass setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the APRM channel can be placed in the conservative condition (i.e., enabling the nonbypass). If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.7. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.5 and SR 3.3.2.1.8

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.5 and SR 3.3.2.1.8 (continued)

of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions.

SR 3.3.2.1.5 is modified by two Notes. Note 1 to SR 3.3.2.1.5 excludes neutron detectors from the CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.7. Note 2 to SR 3.3.2.1.5 excludes the recirculation loop flow signal portion of the channel from the CHANNEL CALIBRATION, since this portion of the channel is calibrated by SR 3.3.2.1.8.

SR 3.3.2.1.8 is modified by a Note that excludes all portions of channel except the recirculation loop flow signal from CHANNEL CALIBRATION. SR 3.3.2.1.5, in conjunction with SR 3.3.2.1.8, results in calibration of the entire channel. Since the recirculation loop flow signal is also a portion of the APRM Neutron Flux-High (Flow Biased) RPS scram Function channels (Table 3.3.1.1-1, RPS Instrumentation, Function 2.b), satisfactory performance of SR 3.3.2.1.8 also results in satisfactory completion of SR 3.3.1.1.12 for the associated APRM Neutron Flux-High (Flow Biased) RPS scram Function channels.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.6

The RWM is automatically bypassed when power is above a specified value. The power level is determined from steam flow signals compensated for steam pressure. The automatic bypass setpoint must be verified periodically to be ≤ 10% RTP. If the RWM low power setpoint is nonconservative, then the RWM is considered inoperable. Alternately, the low power setpoint channel can be placed in the conservative condition (nonbypass). If placed in the nonbypassed condition, the SR is met and the RWM is not considered inoperable. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.7

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch-Shutdown Position Function to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions. The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch-Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs.

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links. This allows entry into MODES 3 and 4 if the Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.9

The RWM will only enforce the proper control rod sequence if the rod sequence is properly input into the RWM computer. This SR ensures that the proper sequence is loaded into the RWM so that it can perform its intended function. The Surveillance is performed once prior to declaring RWM OPERABLE following loading of sequence into RWM, since this is when rod sequence input errors are possible.

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BASES

REFERENCES

1. UFSAR, Section 7.5.8.2.

2. UFSAR, Section 7.16.5.3.

3. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, Supplement for United States, Section S.2.2.1.5, (Revision specified in the COLR).

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

5. UFSAR, Section 14.6.1.2.

6. NRC SER, Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17, December 27, 1987.

7. Letter from T.A. Pickens (BWROG) to G.C. Lainas (NRC), Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, BWROG-8644, August 15, 1986.

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

9. NEDC-30851P-A, Supplement 1, Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation, October 1988.

10. NEDO-33091-A, Revision 2, Improved BPWS Control Rod Insertion Process, July 2004.

B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The feedwater and 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 two 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 each of three trip systems. Each trip system is arranged with a two-out-of-three initiation logic such that two high water level trip signals are necessary for the trip system to actuate. One trip system trips one feedwater pump turbine, another trip system trips the other feedwater pump turbine, and the third trip system trips the main turbine. The channels include electronic equipment (e.g., alarm units) that compares measured input signals with pre- established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a feedwater and main 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 and 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 30% 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 and main turbine high water level trip instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

The LCO requires three channels of the Reactor Vessel Water Level – High (Level 8) 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 and 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 Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the reactor pressure vessel and also corresponds to the top of a 144 inch fuel column (Ref. 3). The actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., alarm unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The trip setpoints are derived from the analytic limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process affects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for

(continued)

BASES

LCO (continued)

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

APPLICABILITY

The feedwater and main turbine high water level trip instrumentation is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists below 25% RTP; therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A Note has been provided to modify the ACTIONS related to feedwater and 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 and 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 and 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

(continued)

BASES

ACTIONS

A.1 (continued)

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 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.

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 and main turbine high water level trip instrumentation cannot perform its design function (feedwater and main turbine high water level trip capability is not maintained). Therefore, continued operation is only permitted for a 2 hour period, during which feedwater and 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 and 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.

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 and 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.

(continued)

Bases

ACTIONS (continued)

C.1 and C.2

With the required channels not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. Alternatively, the affected stop valve(s) may be removed from service since this performs the intended function of the instrumentation. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the feedwater and 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 < 25% RTP from full power conditions in an orderly manner and without challenging plant systems. Required Action C.1 is modified by a Note which states that the Required Action is only applicable if the inoperable channel is the result of an inoperable feedwater pump turbine stop valve or main turbine stop valve. The Note clarifies the situations under which the associated Required Action would be the appropriate Required Action.

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 and 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 taken. This Note is based on the reliability analysis (Ref. 4) 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 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

(continued)

Bases

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2.1 (continued)

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.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limits.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, the CHANNEL FUNCTIONAL TEST is only required to be performed when in MODE 4 for > 24 hours. In MODE 4, the plant is in a condition where a loss of a feedwater pump turbine or a main turbine trip will not jeopardize steady state power operation. The design of the trip systems do not permit functional testing of this trip function without lifting electrical leads. Consequently, testing the trip

(continued)

Bases

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2.2 (continued)

systems on-line poses an unacceptable risk of an inadvertent trip of the feedwater pump turbines and main turbine, resulting in a plant transient. The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling a proper performance of the Surveillance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 and 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.5.9.

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

(continued)

BASES

REFERENCES (continued)

3. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).

4. GENE-770-06-1-A, Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications, December 1992.

5. NRC letter dated June 19, 1995, Amendment 225 for James A. FitzPatrick Nuclear Power Plant.

B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Events. The instruments that monitor these variables are designated as Type A, Category 1, and non-Type A, Category 1, in accordance with Regulatory Guide 1.97 (Ref. 1).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 1.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type A variables so that the control room operating staff can:

- Perform the diagnosis specified in the Emergency Operating Procedures (EOPs). These variables are restricted to preplanned actions for the primary success path of Design Basis Accidents (DBAs), (e.g., loss of coolant accident (LOCA)), and
- Take the specified, preplanned, manually controlled actions for which no automatic control is provided, which are required for safety systems to accomplish their safety function.

The PAM instrumentation LCO also ensures OPERABILITY of Category 1, non-Type A, variables so that the control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;
- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine whether a gross breach of a barrier has occurred; and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Initiate action necessary to protect the public and for an estimate of the magnitude of any potential exposure.

The plant specific Regulatory Guide 1.97 Analysis (Ref. 2) documents the process that identified Type A and Category 1, non-Type A, variables.

Accident monitoring instrumentation that satisfies the definition of Type A in Regulatory Guide 1.97 meets Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3). Category 1, non-Type A, instrumentation is retained in Technical Specifications (TS) because they are intended to assist operators in minimizing the consequences of accidents. Therefore, these Category 1 variables are important for reducing public risk.

LCO

LCO 3.3.3.1 requires two OPERABLE channels for all but one Function to ensure that no single failure prevents the operators from being presented with the information necessary to determine the status of the plant and to bring the plant to, and maintain it in, a safe condition following an accident. Furthermore, provision of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

The exception to the two channel requirement is primary containment isolation valve (PCIV) position. In this case, the important information is the status of the primary containment penetrations. The LCO requires one position indicator for each active PCIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of passive valve or via system boundary status. If a normally active PCIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

The following list is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1 in the accompanying LCO.

1. Reactor Vessel Pressure

Reactor vessel pressure is a Category 1 variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling

(continued)

BASES

LCO

1. Reactor Vessel Pressure (continued)

Systems (ECCS). Two independent pressure transmitters with a range of 0 psig to 1500 psig monitor pressure and associated independent wide range recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

2. Reactor Vessel Water Level

Reactor vessel water level is a Category 1 variable provided to support monitoring of core cooling and to verify operation of the ECCS. The reactor vessel water level channels provide the PAM Reactor Vessel Water Level Function. The reactor vessel water level channels cover a range from -150 inches (just below the bottom of the active fuel) to +224.5 inches, as referenced (zero) from the top of active fuel (TAF). Reactor vessel water level is measured in overlapping stages by separate independent differential pressure transmitters. Two reactor vessel water level (fuel zone) channels monitor the range from -150 inches to +200 inches (TAF). One fuel zone channel consists of a transmitter and indicator and the other channel consists of a transmitter and recorder. Two reactor vessel water level (wide range) channels monitor the range from +14.5 inches to +224.5 inches (TAF). The upper limit corresponds to a level of 63.5 inches below the centerline of the main steam lines. Likewise, one wide range channel consists of a transmitter and indicator and the other channel consists of a transmitter and recorder. These transmitters and associated indicators and recorders provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

The reactor vessel water level wide range instruments are uncompensated for variation in reactor water density and are calibrated to be most accurate at operational pressure and temperature. The fuel level instruments are calibrated for cold conditions.

3. Suppression Pool Water Level (Wide Range)

Suppression pool water level is a Category 1 variable provided to detect a breach in the reactor coolant pressure boundary (RCPB). This variable is also used to verify and provide long term surveillance of ECCS function. The wide

(continued)

BASES

LCO

3. Suppression Pool Water Level (Wide Range) (continued)

range suppression pool water level measurement provides the operator with sufficient information to assess the status of both the RCPB and the water supply to the ECCS. The wide range water level instruments have a range of 1.7 feet to 27.5 feet. Two wide range suppression pool water level signals are transmitted from separate differential pressure transmitters and are continuously monitored by two level indicators and recorded on two recorders in the control room. These transmitters, indicators and recorders provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

4. Drywell Pressure

Drywell pressure is a Category 1 variable provided to detect breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. The drywell pressure channels cover a range of -5 psig to +250 psig. The drywell pressure is measured in overlapping stages by separate independent pressure transmitters. Two drywell pressure (narrow range) channels monitor the range from -5 psig to +5 psig. Two drywell pressure (wide range) channels monitor the range from 0 psig to 250 psig. Each drywell pressure channel consists of a separate independent transmitter with an associated indicator and recorder in the control room. These transmitters and associated indicators and recorders provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

5. Containment High Range Radiation

Containment high range radiation channels are provided to monitor the potential of significant releases of radioactive material and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Two physically separated and redundant radiation detectors with a range of 1 R/hr to 1E8 R/hr are located inside the drywell. The detectors provide a signal to separate process radiation monitors located in the control room. These radiation detectors and associated monitors provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

(continued)

BASES

LCO (continued)

6. Drywell Temperature

Drywell temperature is a Category 1 variable provided to detect a breach in the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Two drywell temperature channels monitor the range from 40°F to 440°F. Each drywell temperature channel consists of a separate temperature sensor, with an associated recorder in the control room. These temperature sensors and associated recorders provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

7. Primary Containment Isolation Valve (PCIV) Position

PCIV position is a Category 1 variable provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. Therefore, this Function is not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured (as noted in footnote (a) to Table 3.3.3.1-1). The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. Each penetration is treated separately and each penetration flow path is considered a separate Function. Therefore, separate Condition entry is allowed for each inoperable penetration flow path.

The PCIV position PAM instrumentation consists of position switches mounted on the valves for the positions to be indicated, associated wiring and control room indicating

(continued)

BASES

LCO

7. Primary Containment Isolation Valve (PCIV) Position (continued)

lamps for active PCIVs (check valves and manual valves are not required to have position indication). These position switches and associated indicators in the control room provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

8. Suppression Chamber Pressure

Suppression chamber pressure is a Category 1 variable provided to verify RCS and containment integrity and to verify the effectiveness of ECCS actions taken to prevent containment breach. Two suppression chamber channels monitor a range from -15 psig to +85 psig. Each channel consists of an independent transmitter and associated recorder in the control room. These transmitters and recorders provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

(continued)

BASES

LCO (continued)

9. Suppression Pool Water Temperature

Suppression pool water temperature is a Category 1 variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature instrumentation allows operators to detect trends in suppression pool water temperature. The suppression pool water temperature is monitored by two redundant channels. Each channel consists of sixteen resistance temperature detectors (RTDs) that monitor temperature over a range of 30°F to 230°F. The RTDs are mounted in thermowells spaced at equal intervals around the periphery of the suppression pool. The sixteen RTD signals are averaged and the resulting bulk temperature signal is sent to redundant indicating recorders in the control room. A minimum of fifteen out of sixteen RTDs are required for channel operability. An evaluation (Ref. 4) demonstrates that the maximum error in suppression pool bulk temperature measurement including channel uncertainty is < 4°F with active pool circulation. Thus a 4°F bias has been employed for conservatism. By specifying 15 RTDs the single failure criteria is accounted for. This evaluation conservatively assumed the failure of RTDs at locations that minimized indicated bulk suppression pool temperature and consequently maximized indicated error. These RTDs and recorders provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channels.

(continued)

BASES

LCO (continued)

10. Drywell Water Level

Drywell Water Level is a Category 1 variable provided to detect whether plant safety functions are being accomplished. Two drywell water level channels monitor the range from 22 feet to 106 feet. Each drywell water level channel consists of level transmitters, with an associated indicator and recorder in the control room. These level transmitters and associated indicators and recorders provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A note has been provided to modify the ACTIONS related to PAM 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 PAM instrumentation channels provide appropriate compensatory measures for separate Functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

(continued)

BASES

ACTIONS (continued)

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is initiated by these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification 5.6.6, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the low probability of an event that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

(continued)

BASES

ACTIONS (continued)

D.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3.1-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1

For the majority of Functions in Table 3.3.3.1-1, if any Required Action and associated Completion Time of Condition C is not met, the plant must be brought to a MODE in which the LCO not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

Since alternate means of monitoring primary containment area radiation have been developed and tested, the Required Action is not to shut down the plant, but rather to follow the directions of Specification 5.6.6. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the other required channel in the associated Function is OPERABLE. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring post-accident parameters, when necessary.

SR 3.3.3.1.1

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 against 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. For the PCIV Position Function, the CHANNEL CHECK consists of verifying the remote indication conforms to expected valve position.

Channel agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.1.2

This SR requires a CHANNEL CALIBRATION to be performed. CHANNEL CALIBRATION is a complete check of the instrument

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1.2 (continued)

loop, including the sensor. The test verifies the channel responds to measured parameter with the necessary range and accuracy. For the PCIV Position Function, the CHANNEL CALIBRATION consists of verifying the remote indication conforms to actual valve position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Regulatory Guide 1.97, Revision 3, Instrumentation For Light-Water-Cooled Nuclear Power Plants To Assess Plant And Environs Conditions During And Following An Accident, May 1983.

2. NRC letter, H. I. Abelson to J. C. Brons dated March 14, 1988, regarding conformance to Regulatory Guide 1.97, Rev. 2. Includes NRR Safety Evaluation Report for Regulatory Guide 1.97 and James A. FitzPatrick Nuclear Power Plant.

3. 10 CFR 50.36(c)(2)(ii).

4. DRF-T23-688-1, Error in FitzPatrick Temperature Measurement Based on Monticello In-plant S/RV Test Data.

B 3.3 INSTRUMENTATION

B 3.3.3.2 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from locations other than the control room. This capability is necessary to protect against the possibility of the control room becoming inaccessible. A safe shutdown condition is defined as MODE 3. With the plant in MODE 3, the safety/relief valves (S/RVs) and the Residual Heat Removal (RHR) System can be used to remove core decay heat and meet all safety requirements. This is accomplished by depressurizing the reactor pressure vessel (RPV) with the use of seven S/RVs and establishing a long term cooling path. Water is pumped from the suppression pool by an RHR pump, through an RHR heat exchanger and to the RPV via the low pressure coolant injection (LPCI) pathway. As reactor water level increases and the main steam lines become flooded, water is recirculated to the suppression pool through the S/RV discharge piping. The long term supply of water from the suppression pool and the ability to operate the RHR System in this closed loop configuration from outside the control room allows operation in a safe shutdown condition for an extended period of time.

In the event that the control room becomes inaccessible, the operators can establish control at the remote shutdown panel and place and maintain the plant in MODE 3. Not all controls and necessary transfer switches are located at the remote shutdown panel. Other major controls are located at the Automatic Depressurization System (ADS) panel and auxiliary shutdown panels. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, or other local stations. The plant is in MODE 3 following a plant shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the Remote Shutdown System control and instrumentation Functions ensures that there is sufficient information available on selected plant parameters to place and maintain the plant in MODE 3 should the control room become inaccessible.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a design capability to promptly shut down the reactor to MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3.

The criteria governing the design and the specific system requirements of the Remote Shutdown System are located in the UFSAR (Refs. 1 and 2).

The Remote Shutdown System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii)(Ref. 3).

LCO

The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls necessary to place and maintain the plant in MODE 3 from locations other than the control room. The instrumentation and controls required are listed in the Technical Requirements Manual (Reference 4). In addition, as stated in the Technical Requirements Manual, this portion of the Technical Requirements Manual is considered part of these Bases. Thus, changes to the instrumentation and controls listed in the Technical Requirements Manual are controlled by the Technical Specifications Bases Control Program.

The controls, instrumentation, and transfer switches are those required for:

- Reactor pressure vessel (RPV) pressure control;
- Decay heat removal;
- RPV inventory control; and
- Safety support systems for the above functions, including Emergency Service water, RHR Service water, cresent area unit coolers and onsite power, including the emergency diesel generators.

The Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown function are OPERABLE. In some cases, the required information or control capability may be available from several alternate sources. In these cases, the Remote Shutdown System is OPERABLE as long as one channel of any of the alternate information or control sources for each Function is OPERABLE.

(continued)

BASES

LCO (continued)

The Remote Shutdown System instruments and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure that the instruments and control circuits will be OPERABLE if plant conditions require that the Remote Shutdown System be placed in operation.

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1 and 2. This is required so that the plant can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODES 3, 4, and 5. In these MODES, the plant is already subcritical and in a condition of reduced Reactor Coolant System energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control becomes unavailable. Consequently, the LCO does not require OPERABILITY in MODES 3, 4, and 5.

ACTIONS

A note has been provided to modify the ACTIONS related to Remote Shutdown System Functions. 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 Remote Shutdown System Functions provide appropriate compensatory measures for separate Functions.

As such, a Note has been provided that allows separate Condition entry for each inoperable Remote Shutdown System Function.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System is inoperable. This includes any function listed in Reference 4, as well as the control and transfer switches.

The Required Action is to restore the Function (both divisions, if applicable) to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1

If the Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODE 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. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring remote shutdown parameters, when necessary.

SR 3.3.3.2.1

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 the instrument channels could be an indication of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1 (continued)

excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.2.2

SR 3.3.3.2.2 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the remote shutdown panel, auxiliary shutdown panels and the local control stations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies the channel responds to measured parameter values with the necessary range and accuracy.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.3 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 16.6.

2. UFSAR, Section 14.5.10.

3. 10 CFR 50.36(c)(2)(ii).

4. Technical Requirements Manual, Appendix D.

B 3.3 INSTRUMENTATION

B 3.3.4.1 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

BASES

BACKGROUND

The ATWS-RPT System initiates an RPT, adding negative reactivity, following events in which a scram does not (but should) occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level—Low Low (Level 2) or Reactor Pressure—High setpoint is reached, the recirculation pump motor generator (MG) drive motor breakers trip.

The ATWS-RPT System (Ref. 1) includes sensors, logic circuits, relays, and switches that are necessary to cause initiation of an RPT. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an ATWS-RPT signal to the trip logic.

The ATWS-RPT logic consists of two trip systems for the Reactor Vessel Water Level—Low Low (Level 2) trip function and two trip systems for the Reactor Pressure —High trip function. Each trip system associated with the Reactor Vessel Water Level—Low Low (Level 2) Function includes two reactor water level channels while each trip system associated with the Reactor Pressure—High Function includes two reactor pressure channels. Each ATWS trip system is a one-out-of-two logic and both trip systems associated with the same function must trip for the ATWS trip logic to actuate. Therefore, the ATWS trip system logic for each Function is one-out-of-two taken twice.

The two channels in each trip system are powered from a common power supply. For each trip function, the two channels in one trip system are powered independently from the two channels in the other trip system. (Divisions 1 and 2). The logic associated with the two trip systems for the Reactor Vessel Water—Low Low (Level 2) trip function and the logic associated with the two trip systems for the Reactor Pressure—High trip function are all powered from one common power supply.

There is one drive motor breaker provided for each of the recirculation pump MGs for a total of two breakers. The output of each trip function logic is provided to both recirculation pump MG drive motor breakers.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS LCO, and APPLICABILITY

The ATWS-RPT is not credited in the safety analysis. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which a scram does not, but should, occur. ATWS-RPT instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

The OPERABILITY of the ATWS-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in both trip systems, with their setpoints within the specified Allowable Value of SR 3.3.4.1.4. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump MG drive motor breakers.

Allowable Values are specified for each ATWS-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the ATWS analysis. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

The individual Functions are required to be OPERABLE in MODE 1 to protect against common mode failures of the Reactor Protection System by providing a diverse trip to mitigate the consequences of a

(continued)

BASES

APPLICABLE SAFETY ANALYSIS LCO, and APPLICABILITY (continued)

postulated ATWS event. The Reactor Pressure—High and Reactor Vessel Water Level—Low Low (Level 2) Functions are required to be OPERABLE in MODE 1, since the reactor is producing significant power and the recirculation system could be at high flow. During this MODE, the potential exists for pressure increases or low water level, assuming an ATWS event. In MODE 2, the reactor is at low power and the recirculation system is at low flow; thus, the potential is low for a pressure increase or low water level, assuming an ATWS event. Therefore, the ATWS-RPT is not necessary. In MODES 3 and 4, the reactor is shut down with all control rods inserted; thus, an ATWS event is not significant and the possibility of a significant pressure increase or low water level is negligible. In MODE 5, the one rod out interlock ensures that the reactor remains subcritical; thus, an ATWS event is not significant. In addition, the reactor pressure vessel (RPV) head is not fully tensioned and no pressure transient threat to the reactor coolant pressure boundary (RCPB) exists.

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

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

Low RPV water level indicates that a reactor scram should have occurred and the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The ATWS-RPT System is initiated at Level 2 to assist in the mitigation of the ATWS event. The resultant reduction of core flow reduces the neutron flux and THERMAL POWER and, therefore, the rate of coolant boiloff.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Water Level—Low Low (Level 2), with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. The Reactor Vessel Water Level—Low Low (Level 2) Allowable Value is chosen so that the system will not be initiated after a Level 3 scram with feedwater still available, and also provides an opportunity for the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems to recover water level if feedwater is not available. The Allowable

(continued)

BASES

APPLICABLE SAFETY ANALYSIS LCO, and APPLICABILITY

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

Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 3).

The HPCI, RCIC and ATWS-RPT initiation functions (as described in Table 3.3.5.1-1, Function 3.a; Table 3.3.5.3-1, Function 1; and LCO 3.3.4.1.a including SR 3.3.4.1.4, respectively) describe the reactor vessel water level initiation function as "Low Low (Level 2)." The Allowable Values associated with the HPCI and RCIC initiation function is different from the Allowable Value associated with the ATWS-RPT initiation function as the ATWS function has a separate analog trip unit. Nevertheless, consistent with the nomenclature typically used in design documents, the "Low Low (Level 2)" designation is retained in describing each of these three initiation functions.

b. Reactor Pressure — High

Excessively high RPV pressure may rupture the RCPB. An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This increases neutron flux and THERMAL POWER, which could potentially result in fuel failure and overpressurization. The Reactor Pressure — High Function initiates an RPT for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power generation. For the overpressurization event, the RPT aids in the termination of the ATWS event and, along with the safety/relief valves (S/RVs), limits the peak RPV pressure to less than the ASME Section III Code Service Level C limits (1500 psig).

The Reactor Pressure — High signals are initiated from four pressure transmitters that monitor reactor steam dome pressure. Four channels of Reactor Pressure — High, with two channels in each trip system, are available and are required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. The Reactor Pressure — High Allowable Value is chosen to provide an adequate margin to the ASME Section III Code Service Level C allowable Reactor Coolant System pressure. The Allowable Value was derived from the analysis performed in Reference 4.

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BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to ATWS-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 inoperable ATWS-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 ATWS-RPT instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with ATWS-RPT capability for each Function maintained (refer to Required Action B.1 Bases), the ATWS-RPT System is capable of performing the intended function. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the same trip system could result in the inability of the ATWS-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE

status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting both Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable 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 would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D must be entered and its Required Actions taken.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS LCO, and APPLICABILITY (continued)

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and both recirculation pumps can be tripped. This requires one channel of the Function in each trip system to each be OPERABLE or in trip, and the recirculation pump MG drive motor breakers to be OPERABLE or in trip.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and that one Function is still maintaining ATWS-RPT trip capability.

Required Action C.1 is intended to ensure that appropriate Actions are taken if multiple, inoperable, untripped channels within both Functions result in both Functions not maintaining ATWS-RPT trip capability. The description of a Function maintaining ATWS-RPT trip capability is discussed in the Bases for Required Action B.1 above.

The 1 hour Completion Time is sufficient for the operator to take corrective action and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period.

D.1 and D.2

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours (Required Action D.2). Alternately, the associated recirculation pump may be removed from service since this performs the intended function of the instrumentation (Required Action D.1). The allowed Completion Time of 6 hours is reasonable, based on operating experience, both to reach MODE 2 from full power conditions and to remove a recirculation pump from service in an orderly manner and without challenging plant systems. Required Action D.1 is modified by a Note which states that the Required Action is only applicable if the inoperable channel is the result of an inoperable RPT breaker. The Note clarifies the situations under which the associated Required Action would be the appropriate Required Action.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains ATWS-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. 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 recirculation pumps will trip when necessary.

SR 3.3.4.1.1

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 the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of this LCO.

SR 3.3.4.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.2 (continued)

FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.1.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.4.1.4. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.1.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.5 (continued)

a breaker is incapable of operating, the associated instrument channels would be inoperable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Figure 7.4-9 Reactor Recirculation System (FCD).
2. 10 CFR 50.36(c)(2)(ii).
3. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).
4. "ATWS Overpressure Analysis for FitzPatrick," GE-NE-A42-00137-2-01, March 2000.
5. GENE-770-06-1-A, Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications, December 1992.

B 3.3 INSTRUMENTATION

B 3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

BASES

BACKGROUND

The purpose of the ECCS instrumentation is to initiate appropriate responses from the systems to ensure that the fuel is adequately cooled in the event of a design basis accident or transient.

For most abnormal operational transients and Design Basis Accidents (DBAs), a wide range of dependent and independent parameters are monitored.

The ECCS instrumentation actuates core spray (CS), low pressure coolant injection (LPCI), high pressure coolant injection (HPCI), Automatic Depressurization System (ADS), and the emergency diesel generators (EDGs). The equipment involved with each of these systems is described in the Bases for LCO 3.5.1, "ECCS—Operating" and LCO 3.8.1, "AC Sources—Operating."

Core Spray System

The CS System may be initiated by either automatic or manual means, although manual initiation requires manipulation of individual pump and valve control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low (Level 1) or Drywell Pressure—High; or both. Each of these diverse variables is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the four trip units associated with each diverse variable are connected to relays whose contacts provide input to two trip systems. Each trip system is arranged in a one-out-of-two taken twice logic for each Function. Each trip system initiates one of two CS pumps and provides an open signal to both injection valves associated with the same CS pump. Once an initiation signal is received by the CS control circuitry, the signal is sealed in until manually reset.

Upon receipt of an initiation signal, if preferred power is available, both CS pumps start after approximately an 11 second time delay. If a CS initiation signal is received when preferred power is not available, the CS pumps start after approximately 11 seconds after the bus is energized by the EDGs.

The normally closed CS test line isolation valve, which is also a

(continued)

BASES

BACKGROUND

Core Spray System (continued)

primary containment isolation valve (PCIV), is closed on a CS initiation signal to allow full system flow assumed in the accident analyses and maintain primary containment isolated in the event CS is not operating.

The CS pump discharge flow and pressure are monitored by a differential pressure indicating switch and a pressure switch, respectively. When the pump is running (as indicated by the pressure switch) and discharge flow is low enough so that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The CS System also monitors the pressure in the reactor to ensure that, before the injection valves open, the reactor pressure has fallen to a value below the CS System's maximum design pressure. The variable is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the trip units are connected to relays whose contacts provide input to two trip systems. Each trip system is arranged in a one-out-of-two taken twice logic. Each trip system provides an open permissive signal for two CS injection valves in one of the two CS Systems.

Low Pressure Coolant Injection System

The LPCI is an operating mode of the Residual Heat Removal (RHR) System, with two LPCI subsystems. The LPCI subsystems may be initiated by automatic or manual means, although manual initiation requires manipulation of individual pump and valve control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low (Level 1); Drywell Pressure—High; or both. Each of these diverse variables is monitored by four redundant transmitters, which, in turn, are connected to four trip units. The outputs of the four trip units associated with each diverse variable are connected to relays whose contacts provide input to two trip systems. Each trip system is arranged in a one-out-of-two taken twice logic for each Function. Each trip system initiates two of the four LPCI pumps, provides an open signal to each LPCI inboard injection valve, provides an open signal to the associated LPCI outboard injection valve, provides an open signal to the associated LPCI heat exchanger bypass valve, and provides a close signal to both recirculation pump

(continued)

BASES

BACKGROUND

Low Pressure Coolant Injection System (continued)

discharge valves. The open signal for the heat exchanger bypass valve is maintained for three minutes to ensure the valve fully opens. Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset.

Upon receipt of an initiation signal, if preferred power is available, LPCI pumps A and D start in approximately one second. LPCI pumps B and C are started in approximately 6 seconds to limit the loading of the preferred power sources. With a loss of preferred power, LPCI pumps A and D start in approximately one second after the bus is energized by the EDGs, and LPCI pumps B and C start 6 seconds after the bus is energized by the EDGs to limit the loading of the EDGs. If one EDG should fail to force parallel, an associated LPCI pump will not start (LPCI pump B or C) to ensure the other EDG is not overloaded.

Each LPCI subsystem's discharge flow is monitored by a differential pressure indicating switch. When a pump is running (as indicated by pump breaker position) and discharge flow is low enough so that pump overheating may occur, the respective minimum flow return line valve is opened. If flow is above the minimum flow setpoint, the valve is automatically closed to allow the full system flow assumed in the analyses.

The normally closed RHR suppression pool cooling isolation return valve, suppression pool spray isolation valves, and containment spray isolation valves (which are also PCIVs) are also closed on a LPCI initiation signal to allow the full system flow assumed in the accident analyses and maintain primary containment isolated in the event LPCI is not operating.

The LPCI System monitors the pressure in the reactor to ensure that, before an injection valve opens, the reactor pressure has fallen to a value below the LPCI System's maximum design pressure. The variable is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the trip units are connected to relays whose contacts provide input to two trip systems. Each trip system is arranged in a one-out-of-two taken twice logic. Each trip system provides an open signal to both inboard injection valves and provides an open permissive signal to the associated outboard injection valve. The open permissive signal for the outboard injection valve is maintained for five minutes to ensure the valve fully

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BASES

BACKGROUND

Low Pressure Coolant Injection System (continued)

opens. Additionally, instruments are provided to close the recirculation pump discharge valves to ensure that LPCI flow does not bypass the core when it injects into the recirculation lines. The variable is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the trip units are connected to relays whose contacts provide input to two trip systems. Each trip system is arranged in a one-out-of-two taken twice logic. Each trip system provides a closure signal to both recirculation pump discharge valves.

Low reactor water level in the shroud is detected by two additional instruments. When the level is greater than the low level setpoint, LPCI may no longer be required, therefore, other modes of RHR (e.g., suppression pool cooling) are allowed. The variable is monitored by two transmitters, which are, in turn, connected to two trip units. The outputs of the trip units are connected to relays whose contacts provide input to one of two trip systems. Each trip system provides a permissive signal to open the associated subsystems containment spray and suppression pool cooling isolation valves. Manual overrides for these isolations below the low level setpoint are provided.

Containment high pressure is detected by four instruments to automatically isolate the containment spray mode of RHR when containment depressurization is not required. This Function also precludes inadvertent diversion of LPCI flow unless containment overpressurization is indicated. This variable is monitored by four pressure switches, whose contacts provide input to two trip systems. The outputs of the contacts are arranged in a one-out-of-two taken twice logic for each trip system. Each trip system provides an input to the associated subsystems containment spray valves.

High Pressure Coolant Injection System

The HPCI System may be initiated by either automatic or manual means, although manual initiation requires manipulation of individual pump and valve control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low (Level 2) or Drywell Pressure—High. Each of these variables is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each Function.

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BASES

BACKGROUND

High Pressure Coolant Injection System (continued)

The HPCI pump discharge flow and pressure are monitored by a flow switch and pressure switch, respectively. When the pump is running (as indicated by the pressure switch) and discharge flow is low enough so that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The HPCI test line isolation valve is closed upon receipt of a HPCI initiation signal to allow the full system flow assumed in the accident analysis.

The HPCI System also monitors the water levels in the condensate storage tanks (CSTs) and the suppression pool because these are the two sources of water for HPCI operation. Reactor grade water in the CSTs is the normal source. The CST suction source consists of two CSTs connected in parallel to the HPCI pump suction. Upon receipt of a HPCI initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless both suppression pool suction valves are open. If the water level in both CSTs falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches are used to detect low water level in each CST. One switch associated with each CST can cause the suppression pool suction valves to open and the CST suction valve to close. The suppression pool suction valves also automatically open and the CST suction valve closes if high water level is detected in the suppression pool. Two level switches monitor suppression pool water level. Either switch can cause the suppression pool suction valves to open and the CST suction valves to close. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be full open before the other automatically closes.

The HPCI provides makeup water to the reactor until the reactor vessel water level reaches the Reactor Vessel Water Level—High (Level 8) setting, at which time the HPCI turbine trips, which causes the turbine's stop valve to close. The logic is two-out-of-two to provide high reliability of the HPCI System. The HPCI System automatically restarts if a Reactor Vessel Water Level—Low Low (Level 2) signal is subsequently received.

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BASES

BACKGROUND (continued)

Automatic Depressurization System

The ADS may be initiated by either automatic or manual means, although manual initiation requires the manipulation of the hand switches associated with each ADS valve. Automatic initiation occurs when signals indicating Reactor Vessel Water Level—Low Low Low (Level 1); confirmed Reactor Vessel Water Level—Low (Level 3); and CS or LPCI Pump Discharge Pressure—High are all present and the ADS Initiation Timer has timed out. There are two transmitters for Reactor Vessel Water Level—Low Low Low (Level 1), and one transmitter for confirmed Reactor Vessel Water Level—Low (Level 3) in each of the two ADS trip systems. Each of these transmitters connects to a trip unit, which then drives a relay whose contacts form the initiation logic.

Each ADS trip system includes a time delay between satisfying the initiation logic and the actuation of the ADS valves. The ADS Initiation Timer time delay setpoint chosen is long enough that the HPCI has sufficient operating time to recover to a level above Level 1, yet not so long that the LPCI and CS Systems are unable to adequately cool the fuel if the HPCI fails to maintain that level. An alarm in the control room is annunciated when either of the timers is timing. Resetting the ADS initiation signals prior to time out of the ADS Initiation Timers resets the ADS Initiation Timers.

The ADS also monitors the discharge pressures of the four LPCI pumps and the two CS pumps. Each ADS trip system includes two discharge pressure permissive switches from one CS and from two LPCI pumps in the associated Division (i.e., Division 1 CS subsystem A and LPCI pumps A and C input to ADS trip system A, and Division 2 CS subsystem B and LPCI pumps B and D input to ADS trip system B). The signals are used as a permissive for ADS actuation, indicating that there is a source of core coolant available once the ADS has depressurized the vessel. Any one of the six low pressure pumps is sufficient to permit automatic depressurization. The switches associated with one ADS trip system also provide signals to the other ADS trip system, but these signals are not required for the other ADS trip system to be considered OPERABLE.

The ADS logic in each trip system is arranged in two strings. Each string has a contact from Reactor Vessel Water Level—Low Low Low (Level 1). One of the two strings in each trip system must also have a confirmed Reactor Vessel Water Level—Low (Level 3). All contacts in

(continued)

BASES

BACKGROUND

Automatic Depressurization System (continued)

both logic strings must close, the ADS initiation timer must time out, and a CS or LPCI pump discharge pressure signal must be present to initiate an ADS trip system. Either the A or B trip system will cause all the ADS relief valves to open. Once the ADS initiation signal is present, it is individually sealed in until manually reset.

Manual inhibit switches are provided in the control room for the ADS; however, their function is not required for ADS OPERABILITY (provided ADS is not inhibited when required to be OPERABLE).

Emergency Diesel Generators

The EDGs may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low (Level 1) or Drywell Pressure—High. Each of these diverse variables is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the four trip units associated with each diverse variable are connected to relays whose contacts provide input to two trip systems. Each trip system is arranged in a one-out-of-two taken twice logic for each Function. One trip system will start EDG-A and EDG-C. The other trip system will start EDG-B and EDG-D. The EDGs receive their initiation signals from the LPCI and CS System initiation logic. The EDGs are also initiated upon loss of voltage signals. (Refer to the Bases for LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," for a discussion of these signals.) The EDGs can also be started manually from the control room and locally from the associated EDG room. The EDG initiation signal is a sealed in signal and must be manually reset. The EDG initiation logic is reset by resetting the associated ECCS initiation logic. Upon receipt of an ECCS initiation signal, each EDG is automatically started, is ready to load in approximately 10 seconds, and will run in standby conditions (rated voltage and speed, with the EDG output breaker open). The EDGs will only energize their respective emergency buses if a loss of preferred power occurs. (Refer to Bases for LCO 3.3.8.1.)

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BASES (continued)

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of References 1, 2, 3, and 4. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post LOCA peak cladding temperature to less than the 10 CFR 50.46 limits.

ECCS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the ECCS instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Table 3.3.5.1-1 is modified by a footnote which is added to show that certain ECCS instrumentation Functions also perform EDG initiation.

Allowable Values are specified for each ECCS Function specified in the table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis or other appropriate documents. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g.,

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

drift and calibration uncertainties).

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS (or EDG) initiation to mitigate the consequences of a design basis transient or accident. To ensure reliable ECCS and EDG function, a combination of Functions is required to provide primary and secondary initiation signals.

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

Core Spray and Low Pressure Coolant Injection Systems
1.a, 2.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. The low pressure ECCS and associated EDGs are initiated at Level 1 to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The EDGs are initiated from Function 1.a and 2.a. The Reactor Vessel Water Level—Low Low Low (Level 1) is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in Reference 3. In addition, the Reactor Vessel Water Level—Low Low Low (Level 1) Function is directly assumed in the analysis of the recirculation line break (Refs. 1, 2, and 4). The core cooling function of the ECCS, along with the scram action of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low Low Low (Level 1) signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level—Low Low Low (Level 1) Allowable Value is chosen to allow time for the low pressure core flooding systems to activate and provide adequate cooling. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 6).

Thus, four channels of the CS and LPCI Reactor Vessel Water Level—Low Low Low (Level 1) Function are only required to be OPERABLE when the ECCS are required to be OPERABLE to ensure that no single instrument failure can preclude ECCS initiation.

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

1.b, 2.b. Drywell Pressure—High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The low pressure ECCS and associated EDGs are initiated upon receipt of the Drywell Pressure—High Function in order to minimize the possibility of fuel damage. The EDGs are initiated from Function 1.b and 2.b. The Drywell Pressure—High Function, along with the Reactor Water Level—Low Low Low (Level 1) Function, is directly assumed in the analysis of the recirculation line break (Refs. 1, 2, and 4). The core cooling function of the ECCS, along with the scram action of the RPS, 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 transmitters that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment.

The Drywell Pressure—High Function is required to be OPERABLE when the ECCS or EDG(s) are required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the CS and LPCI Drywell Pressure—High Function are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude ECCS and EDG initiation. In MODES 4 and 5, the Drywell Pressure—High Function is not required, since there is insufficient energy in the reactor to pressurize the primary containment to Drywell Pressure—High setpoint. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems and to LCO 3.8.1 for Applicability Bases for the EDGs.

1.c, 2.c. Reactor Pressure—Low (Injection Permissive)

Low reactor pressure signals are used as permissives for the low pressure ECCS subsystems. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. The Reactor Pressure—Low is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in Reference 3. In addition, the Reactor Pressure—Low Function is directly assumed in the analysis of the recirculation line break (Refs. 1, 2, and 4). The core cooling function of the ECCS, along with the scram action of the RPS, ensures

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

1.c, 2.c. Reactor Pressure — Low (Injection Permissive) (continued)

that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The Reactor Pressure — Low signals are initiated from four pressure transmitters that sense the reactor dome pressure.

The Allowable Value is low enough to prevent overpressuring the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

Four channels of Reactor Pressure — Low Function are only required to be OPERABLE when the ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude ECCS initiation.

1.d, 2.f. Core Spray and Low Pressure Coolant Injection Pump Start-Time Delay Relay

The purpose of these time delay relays is to stagger the start of the CS and LPCI pumps to enable sequential loading of the appropriate AC source. The CS and LPCI Pump Start-Time Delay Relays are assumed to be OPERABLE in the accident analyses requiring ECCS initiation. That is, the analyses assumes that the pumps will initiate when required and no excess loading of the power sources will occur.

There are two CS and four LPCI Pump Start-Time Delay Relays, one in each of the CS and LPCI pump start circuits. While each time delay relay is dedicated to a single pump start circuit, a single failure of a CS or LPCI Pump Start-Time Delay Relay could result in the failure of a CS pump and both the LPCI pumps powered from the same emergency bus to perform their intended function within the assumed ECCS response time (e.g., as in the case where one inoperable time delay relay results in more than one pump starting at nearly the same time). In the worst case this would still leave the other three low pressure ECCS pumps OPERABLE; thus, the single failure of one instrument does not preclude ECCS initiation. The Allowable Values for the CS and LPCI Pump Start-Time Delay Relays are chosen to be short enough so that ECCS operation is within the time period assumed in the accident analyses.

Each CS and LPCI Pump Start-Time Delay Relay Function is required to be OPERABLE only when the associated CS and LPCI subsystem is required to be OPERABLE.

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

1.e, 2.g, 1.f. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow—Low (Bypass), Core Spray Pump Discharge Pressure—High (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating at reduced flows. The minimum flow line valve is opened when low flow is sensed (if the associated pump is detected to be operating), and the valve is automatically closed when the flow rate is adequate to protect the pump. The CS pump is detected to be operating by sensing high pump discharge pressure, while the LPCI pumps are detected to be operating by the use of pump motor breaker auxiliary contacts. The LPCI and CS Pump Discharge Flow—Low and the CS Pump Discharge Pressure—High (Bypass) Functions are assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the low pressure ECCS flows assumed during the transients and accidents analyzed in References 1, 2, 3, and 4 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. One differential pressure indicating switch per CS pump and one differential pressure indicating switch per LPCI subsystem are used to detect the associated subsystems' flow rates. In addition, one pressure switch per CS pump is used to detect the associated pumps discharge pressure. The logic is arranged such that each differential pressure indicating switch causes its associated minimum flow valve to open. For CS, both the differential pressure indicating switch and the pressure switch must actuate to cause the valve to open. The logic will close the minimum flow valve once the closure setpoint of the associated differential pressure indicating switch is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 10 seconds after the switches detect low flow. The time delay is provided to limit reactor vessel inventory loss during the startup of the RHR shutdown cooling mode. The Pump Discharge Flow—Low Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. The Core Spray Pump Discharge Pressure—High (Bypass) Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode and high enough to avoid any condition that results in a discharge pressure permissive when the CS pump is aligned for injection and the pump is not running.

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

1.e, 2.g, 1.f. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow — Low (Bypass), Core Spray Pump Discharge Pressure — High (Bypass) (continued)

Each channel of Pump Discharge Flow — Low Function (two CS channels and four LPCI channels) and each channel of Core Spray Pump Discharge Pressure — High (Bypass) are only required to be OPERABLE when the associated ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude the ECCS function.

2.d. Reactor Pressure — Low (Recirculation Discharge Valve Permissive)

Low reactor pressure signals are used as permissives for recirculation discharge valve closure. This ensures that the LPCI subsystems inject into the proper RPV location assumed in the safety analysis. The Reactor Pressure — Low is one of the Functions assumed to be OPERABLE and capable of closing the valve during the transients analyzed in Reference 3. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Pressure — Low Function is directly assumed in the analysis of the recirculation line break (Refs. 1, 2 and 4).

The Reactor Pressure — Low signals are initiated from four pressure transmitters that sense the reactor dome pressure.

The Allowable Value is chosen to ensure that the valves close prior to commencement of LPCI injection flow into the core, as assumed in the safety analysis.

Four channels of the Reactor Pressure — Low Function are only required to be OPERABLE in MODES 1, 2, and 3 with the associated recirculation pump discharge valve open. With the valve(s) closed, the function of the instrumentation has been performed; thus, the Function is not required. In MODES 4 and 5, the loop injection location is not critical since LPCI injection through the recirculation loop in either direction will still ensure that LPCI flow reaches the core (i.e., there is no significant reactor steam dome back pressure).

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

2.e. Reactor Vessel Shroud Level (Level 0)

The Reactor Vessel Shroud Level (Level 0) Function is provided as a permissive to allow the RHR System to be manually aligned from the LPCI mode to the suppression pool cooling/spray or drywell spray modes. The reactor vessel shroud level permissive ensures that water in the vessel is approximately two thirds core height before the manual transfer is allowed. This ensures that LPCI is available to prevent or minimize fuel damage. This function may be overridden during accident conditions as allowed by plant procedures. Reactor Vessel Shroud Level (Level 0) Function is implicitly assumed in the analysis of the recirculation line break (Refs. 1, 2 and 4) since the analysis assumes that no LPCI flow diversion occurs when reactor water level is below Level 0.

Reactor Vessel Shroud Level (Level 0) signals are initiated from two level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Shroud Level (Level 0) Allowable Value is chosen to allow the low pressure core flooding systems to activate and provide adequate cooling before allowing a manual transfer. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 6).

Two channels of the Reactor Vessel Shroud Level (Level 0) Function are only required to be OPERABLE in MODES 1, 2, and 3. In MODES 4 and 5, the specified initiation time of the LPCI subsystems is not assumed, and other administrative controls are adequate to control the valves associated with this Function (since the systems that the valves are opened for are not required to be OPERABLE in MODES 4 and 5 and are normally not used).

2.h. Containment Pressure - High

The Containment Pressure—High Function is provided as an isolation of the containment spray mode of RHR on decreasing containment pressure following manual actuation of the system. This isolation ensures excessive depressurization of the containment does not occur due to containment spray actuation. This Function also serves as an interlock permissive to allow the RHR System to be manually aligned from the LPCI mode to the containment spray mode after containment

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

2.h. Containment Pressure – High (continued)

pressure has exceeded the trip setting. The permissive ensures that containment pressure is elevated before the manual transfer is allowed. This ensures that LPCI is available to prevent or minimize fuel damage until such time that the operator determines that containment pressure control is needed. The Containment Pressure—High Function is implicitly assumed in the analysis of LOCAs inside containment (Refs. 1, 2, and 4) since the analysis assumes that containment spray occurs when containment pressure is high.

Containment Pressure—High signals are initiated from four pressure switches that sense drywell pressure. The Containment Pressure—High lower Allowable Value is chosen to ensure isolation of containment spray prior to a negative containment pressure occurring.

This maintains margin to the negative design pressure and minimizes operation of the reactor building-to-suppression chamber vacuum breakers, which in turn prevents de-inerting the atmosphere. The upper Allowable Value is chosen to ensure containment spray is not isolated when there may be a need for containment spray.

Four channels of the Containment Pressure—High Function are only required to be OPERABLE in MODES 1, 2, and 3. In MODES 4 and 5, containment spray is not assumed to be initiated, and other administrative controls are adequate to control the valves that this Function isolates.

High Pressure Coolant Injection System
3.a. 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, the HPCI System is initiated at Level 2 to maintain level above the top of the active fuel. In addition, the Standby Gas Treatment (SGT) System suction valves receive an open signal so that the gland seal exhaust from the HPCI turbine can be treated. Opening of the SGT System suction valves results in automatic starting of the SGT System. The Reactor Vessel Water Level—Low Low (Level 2) is one of the Functions assumed to be OPERABLE and capable of initiating HPCI during the transients analyzed in Reference 3. Additionally, the Reactor Vessel Water Level—Low Low (Level 2) Function associated with HPCI is assumed to be OPERABLE and capable of initiating HPCI in the analysis of line breaks (Refs. 1

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

and 4). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low Low (Level 2) signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level—Low Low (Level 2) Allowable Value is high enough such that for complete loss of feedwater flow, the Reactor Core Isolation Cooling (RCIC) System flow with HPCI assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Reactor Vessel Water Level—Low Low Low (Level 1). The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 6).

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

Four channels of Reactor Vessel Water Level—Low Low (Level 2) Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI initiation. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.b. Drywell Pressure—High

High pressure in the drywell could indicate a break in the RCPB. The HPCI System is initiated upon receipt of the Drywell Pressure—High Function in order to minimize the possibility of fuel damage. In addition, SGT System suction valves receive an open signal so that the gland seal exhaust from the HPCI turbine can be treated. Opening of the SGT System suction valves results in automatic starting of SGT.

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3.b. Drywell Pressure—High (continued)

The Drywell Pressure—High Function, along with the Reactor Water Level—Low Low (Level 2) Function, is assumed to be OPERABLE and capable of initiating HPCI in the analysis of line breaks (Refs. 1 and 4). The core cooling function of the ECCS, along with the scram action of the RPS, 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 transmitters that sense drywell pressure. The Allowable Value was selected to be as low as possible to be indicative of a LOCA inside primary containment.

Four channels of the Drywell Pressure—High Function are required to be OPERABLE when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI initiation. Refer to LCO 3.5.1 for the Applicability Bases for the HPCI System.

3.c. Reactor Vessel Water Level—High (Level 8)

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to trip the HPCI turbine to prevent overflow into the main steam lines (MSLs). The Reactor Vessel Water Level—High (Level 8) Function is not assumed in the accident and transient analyses. It was retained since it is a potentially significant contributor to risk.

Reactor Vessel Water Level—High (Level 8) signals for HPCI are initiated from two level transmitters from the narrow range water level measurement instrumentation. Both Level 8 signals are required in order to trip the HPCI turbine. This ensures that no single instrument failure can preclude HPCI initiation. The Reactor Vessel Water Level—High (Level 8) Allowable Value is chosen to prevent flow from the HPCI System from overflowing into the MSLs. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 6).

Two channels of Reactor Vessel Water Level—High (Level 8) Function are required to be OPERABLE only when HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

3.d. Condensate Storage Tank Level—Low

Low level in the CSTs indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valve between HPCI and the CSTs is open and, upon receiving a HPCI initiation signal, water for HPCI injection would be taken from the CSTs. However, if the water level in both CSTs falls below a preselected level, the suppression pool suction valves automatically open. Opening the suppression pool suction valves causes the CST suction valve to automatically close. This ensures that an adequate supply of makeup water is available to the HPCI pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be full open before the CST suction valve automatically closes. The Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

Condensate Storage Tank Level—Low signals are initiated from four level switches (2 per CST). The logic is arranged such that one switch associated with each CST must actuate to cause the suppression pool suction valves to open and the CST suction valve to close. The Condensate Storage Tank Level—Low Function Allowable Value is high enough to ensure (15,600 gallons of water is available in each CST) adequate pump suction head while water is being taken from the CSTs.

Four channels of the Condensate Storage Tank Level—Low Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.e. Suppression Pool Water Level—High

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the safety/relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CSTs to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be full open before

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3.e. Suppression Pool Water Level—High (continued)

the CST suction valve automatically closes.

This Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

Suppression Pool Water Level—High signals are initiated from two level switches. The logic is arranged such that either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The Allowable Value for the Suppression Pool Water Level-High Function is chosen to ensure that HPCI will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

Two channels of Suppression Pool Water Level—High Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.f, 3.g. High Pressure Coolant Injection Pump Discharge Flow—Low (Bypass), High Pressure Coolant Injection Pump Discharge Pressure—High (Bypass)

The minimum flow instruments are provided to protect the HPCI pump from overheating when the pump is operating at reduced flow. The minimum flow line valve is opened when low flow is sensed (if the HPCI pump is operating), and the valve is automatically closed when the discharge flow rate is adequate to protect the pump. Pump operation is determined by sensing high pump discharge pressure. The High Pressure Coolant Injection Pump Discharge Flow—Low and Pump Discharge Pressure—High Functions are assumed to be OPERABLE and capable of opening the minimum flow valve to protect the pump and closing the minimum flow valve to ensure that the ECCS flow assumed during the transients and accidents analyzed in References 1, 2 and 4 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow switch is used to detect the HPCI System's flow rate and one pressure switch is used to detect the HPCI pump discharge pressure. The logic is arranged such that the flow switch and pressure switch

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3.f, 3.g. High Pressure Coolant Injection Pump Discharge Flow—Low (Bypass), High Pressure Coolant Injection Pump Discharge Pressure—High (Bypass) (continued)

must actuate to cause the minimum flow valve to open. The logic will close the minimum flow valve once the flow closure setpoint is exceeded.

The High Pressure Coolant Injection Pump Discharge Flow—Low Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. The High Pressure Coolant Injection Pump Discharge Pressure—High (Bypass) Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode and high enough to avoid any condition that results in a discharge pressure permissive when the HPCI pump is aligned for injection and the pump is not running.

One channel of each Function is required to be OPERABLE when the HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

Automatic Depressurization System
4.a, 5.a. Reactor Vessel Water Level-Low Low Low (Level 1)

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, ADS receives one of the signals necessary for initiation from this Function. The Reactor Vessel Water Level—Low Low Low (Level 1) is one of the Functions assumed to be OPERABLE and capable of initiating the ADS during the accident analyzed in References 1, 2, and 4. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low Low Low (Level 1) signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low Low (Level 1) Function are required to be OPERABLE only when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

4.a, 5.a. Reactor Vessel Water Level-Low Low Low (Level 1) (continued)

ADS initiation. Two channels input to ADS trip system A, while the other two channels input to ADS trip system B. Refer to LCO 3.5.1 for ADS Applicability Bases.

The Reactor Vessel Water Level—Low Low Low (Level 1) Allowable Value is chosen to allow time for the low pressure core flooding systems to initiate and provide adequate cooling. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 6).

4.b, 5.b. Automatic Depressurization System Initiation Timer

The purpose of the Automatic Depressurization System Initiation Timer is to delay depressurization of the reactor vessel to allow the HPCI System time to maintain reactor vessel water level. Since the rapid depressurization caused by ADS operation is one of the most severe transients on the reactor vessel, its occurrence should be limited. By delaying initiation of the ADS Function, the operator is given the chance to monitor the success or failure of the HPCI System to maintain water level, and then to decide whether or not to allow ADS to initiate, to delay initiation further by recycling the timer, or to inhibit initiation permanently. The Automatic Depressurization System Initiation Timer Function is assumed to be OPERABLE for the accident analyses of Reference 1, 2, and 4 that require ECCS initiation and assume failure of the HPCI System.

There are two Automatic Depressurization System Initiation Timer relays, one in each of the two ADS trip systems. The Allowable Value for the Automatic Depressurization System Initiation Timer is chosen so that there is still time after depressurization for the low pressure ECCS subsystems to provide adequate core cooling.

Two channels of the Automatic Depressurization System Initiation Timer Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (One channel inputs to ADS trip system A, while the other channel inputs to ADS trip system B. Refer to LCO 3.5.1 for ADS Applicability Bases.

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

4.c, 5.c. Reactor Vessel Water Level—Low (Level 3)

The Reactor Vessel Water Level—Low (Level 3) Function is used by the ADS only as a confirmatory low water level signal. ADS receives one of the signals necessary for initiation from Reactor Vessel Water Level—Low Low Low (Level 1) signals. In order to prevent spurious initiation of the ADS due to spurious Level 1 signals, a Level 3 signal must also be received before ADS initiation commences.

Reactor Vessel Water Level—Low (Level 3) signals are initiated from two level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Allowable Value for Reactor Vessel Water Level—Low (Level 3) is selected to be the same as the RPS Level 3 scram Allowable Value for convenience.

Refer to LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," for the Bases discussion of this Function. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 6).

Two channels of Reactor Vessel Water Level—Low (Level 3) Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. One channel inputs to ADS trip system A, while the other channel inputs to ADS trip system B. Refer to LCO 3.5.1 for ADS Applicability Bases.

4.d, 4.e, 5.d, 5.e. Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure—High

The Pump Discharge Pressure—High signals from the CS and LPCI pumps are used as permissives for ADS initiation, indicating that there is a source of low pressure cooling water available once the ADS has depressurized the vessel. Pump Discharge Pressure—High is one of the Functions assumed to be OPERABLE and capable of permitting ADS initiation during the events analyzed in References 1, 2, and 4 with an assumed HPCI failure. For these events the ADS depressurizes the reactor vessel so that the low pressure ECCS can perform the core cooling function. This core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

4.d, 4.e, 5.d, 5.e. Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure—High (continued)

temperature remains below the limits of 10 CFR 50.46.

Pump discharge pressure signals are initiated from twelve pressure switches, two on the discharge side of each of the six low pressure ECCS pumps. In order to generate an ADS permissive in one trip system, it is necessary that only one pump (both channels for the pump) indicate the high discharge pressure condition. The Pump Discharge Pressure—High Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode and high enough to avoid any condition that results in a discharge pressure permissive when the CS and LPCI pumps are aligned for injection and the pumps are not running. The actual operating point of this function is not assumed in any transient or accident analysis. However, this function is implicitly assumed to operate to provide the ADS permissive to depressurize the RCS to allow the ECCS low pressure systems to operate.

Twelve channels of Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure—High Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Two CS channels associated with CS pump A and four LPCI channels associated with LPCI pumps A and C are required for trip system A. Two CS channels associated with CS pump B and four LPCI channels associated with LPCI pumps B and D are required for trip system B. Refer to LCO 3.5.1 for ADS Applicability Bases.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS 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 ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable ECCS instrumentation channel.

(continued)

BASES

ACTIONS (continued)

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.1-1. The applicable Condition referenced in the table is Function dependent. Each time a channel is discovered inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

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

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 redundant automatic initiation capability being lost for the feature(s). Required Action B.1 features would be those that are initiated by Functions 1.a, 1.b, 2.a, and 2.b (e.g., low pressure ECCS). The Required Action B.2 system would be HPCI. For Required Action B.1, redundant automatic initiation capability is lost if (a) two or more Function 1.a channels are inoperable and untripped such that both trip systems lose initiation capability, (b) two or more Function 2.a channels are inoperable and untripped such that both trip systems lose initiation capability, (c) two or more Function 1.b channels are inoperable and untripped such that both trip systems lose initiation capability, or (d) two or more Function 2.b channels are inoperable and untripped such that both trip systems lose initiation capability. For low pressure ECCS, since each inoperable channel would have Required Action B.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated system of low pressure ECCS and EDGs to be declared inoperable. However, since channels in both associated low pressure ECCS subsystems (e.g., both CS subsystems) are inoperable and untripped, and the Completion Times started concurrently for the channels in both subsystems, this results in the affected portions in the associated low pressure ECCS and EDGs being concurrently declared inoperable.

For Required Action B.2, redundant automatic HPCI initiation capability is lost if two or more Function 3.a or two or more Function 3.b channels are inoperable and untripped such that trip capability is lost. In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action B.3 is not appropriate and the HPCI System must be declared inoperable within 1 hour.

(continued)

BASES

ACTIONS

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

Notes are also provided (the Note to Required Action B.1 and the Note to Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed. Required Action B.1 (the Required Action for certain inoperable channels in the low pressure ECCS subsystems) is not applicable to Functions 2.e and 2.h, since these Functions provide backup to administrative controls ensuring that operators do not divert LPCI flow from injecting into the core when needed, and do not spray the containment unless needed. Thus, a total loss of Function 2.e or 2.h capability for 24 hours is allowed, since the LPCI subsystems remain capable of performing their intended function.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that a redundant feature in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable, untripped channels within the same Function as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCI System cannot be automatically initiated due to two inoperable, untripped channels for the associated Function in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.3. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

(continued)

BASES

ACTIONS

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

Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

C.1 and C.2

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same Function result in redundant automatic initiation capability being lost for the feature(s). Required Action C.1 features would be those that are initiated by Functions 1.c, 1.d, 2.c, 2.d, and 2.f (i.e., low pressure ECCS). Redundant automatic initiation capability is lost if either (a) two or more Function 1.c channels are inoperable such that both trip systems lose initiation capability, (b) two Function 1.d channels are inoperable, (c) two or more Function 2.c channels are inoperable such that both trip systems lose initiation capability, (d) two or more Function 2.d channels are inoperable such that both trip systems lose initiation capability, or (e) three Function 2.f channels are inoperable. In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action C.2 is not appropriate and the feature(s) associated with the inoperable channels must be declared inoperable within 1 hour. Since each inoperable channel would have Required Action C.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated system to be declared inoperable. However, since channels for both low pressure ECCS subsystems are inoperable (e.g., both CS subsystems), and the Completion Times started concurrently for the channels in both subsystems, this results in the affected portions in both subsystems being concurrently declared inoperable. For Functions 1.c, 1.d, 2.c, 2.d, and 2.f, the affected portions are the associated low pressure ECCS pumps.

The Note states that Required Action C.1 is only applicable for Functions 1.c, 1.d, 2.c, 2.d, and 2.f. Required Action C.1 is not applicable to Function 3.c (which also requires entry into this Condition if a channel in this Function is inoperable), since the loss of one channel results in a loss of the Function (two-out-of-two logic). This loss was considered during the development of Reference 7 and considered acceptable for the 24 hours allowed by Required Action C.2.

(continued)

BASES

ACTIONS

C.1 and C.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." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both subsystems (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

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

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCI System. Automatic component initiation capability is lost if two Function 3.d channels associated with one CST or two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCI System must be declared inoperable within 1 hour after discovery of loss of HPCI initiation capability. As noted, Required Action D.1 is only applicable if the HPCI pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (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." For Required Action D.1, the Completion Time only begins upon discovery that the HPCI System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the HPCI System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCI suction piping), Condition H must be entered and its Required Action taken.

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the Core Spray and Low Pressure Coolant Injection Pump Discharge Flow—Low Bypass and the Core Spray Pump Discharge Pressure—High Functions result in redundant automatic initiation capability being lost for the feature(s). For Required Action E.1, the features would be those that are initiated by Functions 1.e, 1.f, and 2.g (e.g., low pressure ECCS). Redundant automatic initiation capability is lost if (a) two Function 1.e channels are inoperable, (b) two Function 1.f channels are

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

inoperable, (c) two Function 2.g channels are inoperable, or (d) one Function 1.e channel and one Function 1.f channel associated with different CS pumps are inoperable. Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump to be declared inoperable. However, since channels for more than one low pressure ECCS pump are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS pumps, this results in the affected low pressure ECCS pumps being concurrently declared inoperable.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the subsystem associated with each inoperable channel must be declared inoperable within 1 hour. A Note is also provided (the Note to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCI Functions 3.f and 3.g since the loss of one channel results in a loss of the Function (one-out-of- one logic). This loss was considered during the development of Reference 7 and considered acceptable for the 7 days allowed by Required Action E.2.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

For Required Action E.1, the Completion Time only begins upon discovery that a redundant feature in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable, such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation, such that the valve would not automatically close, a portion of the pump flow could be diverted from the reactor vessel injection path,

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

causing insufficient core cooling. These consequences can be averted by the operator's manual control of the valve, which would be adequate to maintain ECCS pump protection and required flow. Furthermore, other ECCS pumps would be sufficient to complete the assumed safety function if no additional single failure were to occur. The 7 day Completion Time of Required Action E.2 to restore the inoperable channel to OPERABLE status is reasonable based on the remaining capability of the associated ECCS subsystems, the redundancy available in the ECCS design, and the low probability of a DBA occurring during the allowed out of service time. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

F.1 and F.2

Required Action F.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within similar ADS trip system A and B Functions result in redundant automatic initiation capability being lost for the ADS. Redundant automatic initiation capability is lost if either (a) one Function 4.a channel and one Function 5.a channel are inoperable and untripped, or (b) one Function 4.c channel and one Function 5.c channel are inoperable and untripped.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action F.2 is not appropriate and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action F.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable, untripped channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE. If either HPCI or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. 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 F.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.b channel and one Function 5.b channel are inoperable, or (b) a combination of Function 4.d, 4.e, 5.d, and 5.e channels are inoperable such that channels associated with five or more low pressure ECCS pumps are inoperable.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability.

(continued)

BASES

ACTIONS

G.1 and G.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." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE (Required Action G.2). If either HPCI or RCIC is inoperable, the time shortens to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

H.1

With any Required Action and associated Completion Time not met, the associated feature(s) may be incapable of performing the intended function, and the supported feature(s) associated with inoperable untripped channels must be declared inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1.

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 as follows: (a) for Functions 3.c, 3.f, and 3.g; (b) for Functions other than 3.c, 3.f, and 3.g provided the associated Function or redundant Function maintains ECCS initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 7) 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 ECCS will initiate when necessary.

SR 3.3.5.1.1

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 the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK guarantees that undetected outright channel failure is limited; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.1.3 and SR 3.3.5.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.4

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.5.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analyses. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.5.
2. UFSAR, Section 14.6.
3. UFSAR, Section 14.5.
4. NEDC-31317P, Revision 2, James A. FitzPatrick Nuclear Power Plant, SAFER/GESTR-LOCA, Loss-of-Coolant Accident Analysis, April 1993.
5. 10 CFR 50.36(c)(2)(ii).
6. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).
7. NEDC-30936P-A, BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation), Part 2, December 1988.

B 3.3 INSTRUMENTATION

B 3.3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control Instrumentation

BASES

BACKGROUND

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.1.3 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in MODES 1, 2, and 3 in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," or LCO 3.3.6.1, "Primary Containment Isolation instrumentation".

With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in MODES 4 and 5 to protect Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

(continued)

BASES

BACKGROUND (continued)

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control," and the definition of DRAIN TIME. There are functions that are required for manual initiation or operation of the ECCS injection/spray subsystem required to be OPERABLE by LCO 3.5.2 and other functions that support automatic isolation of Residual Heat Removal subsystem and Reactor Water Cleanup system penetration flow path(s) on low RPV water level.

The RPV Water Inventory Control Instrumentation supports operation of core spray (CS) and low pressure coolant injection (LPCI). The equipment involved with each of these systems is described in the Bases for LCO 3.5.2.

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV, LCO, water inventory control is required in MODES 4 and 5 to protect and Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not postulated in MODES 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is postulated in which a single operator error or initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (e.g., seismic event, loss of normal power, single human error). It is assumed, based on engineering judgment, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

Core Spray and Low Pressure Coolant Injection Systems

1.a, 2.a. Reactor Pressure - Low (Injection Permissive)

Low reactor pressure signals are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. This function ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. While it is assured during MODES 4 and 5 that the reactor pressure will be below the ECCS maximum design pressure, the Reactor Pressure – Low signals are assumed to be OPERABLE and capable of permitting initiation of the ECCS. The Reactor Pressure - Low signals are initiated from four pressure transmitters that sense the reactor dome pressure. The Allowable Value is low enough to prevent overpressuring the equipment in the low pressure ECCS.

The four channels of Reactor Pressure - Low Function are required to be OPERABLE in MODES 4 and 5 when ECCS manual initiation is required to be OPERABLE by LCO 3.5.2.

1.b, 2.b, and 1.c. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow — Low (Bypass), Core Spray Pump Discharge Pressure — High (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump.

One differential pressure indicating switch per CS pump and one differential pressure indicating switch per LPCI subsystem are used to detect the associated subsystems' flow rates. In addition, one pressure switch per CS pump is used to detect the associated pumps discharge pressure. The logic is arranged such that each differential pressure indicating switch causes its associated minimum flow valve to open. For CS both the differential pressure indicating switch and the pressure switch must actuate to cause the valve to open. The logic will close the minimum flow valve once the closure setpoint of the associated differential pressure indicating switch is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 10 seconds after the switches detect low flow. The time delay is provided to limit reactor vessel inventory loss during the

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

1.b, 2.b, and 1.c. Core Spray and Low Pressure Coolant Injection Pump Discharge Flow — Low (Bypass), Core Spray Pump Discharge Pressure — High (Bypass) (continued)

startup of the Residual Heat Removal (RHR) shutdown cooling mode.

The Pump Discharge Flow - Low Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. The Core Spray Pump Discharge Pressure-High (Bypass) Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode and high enough to avoid any condition that results in a discharge pressure permissive when the CS pump is aligned for injection and the pump is not running.

One channel of the Pump Discharge Flow - Low Function and one channel of Core Spray Pump Discharge Pressure – High (Bypass) is required to be OPERABLE in MODES 4 and 5 when the associated Core Spray or LPCI pump is required to be OPERABLE by LCO 3.5.2 to ensure the pumps are capable of injecting into the Reactor Pressure Vessel when manually initiated.

RHR System Isolation

3.a - Reactor Vessel Water Level - Low, Level 3

The definition of Drain Time allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level - Low, Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level - Low, Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low, Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

Instrumentation Reactor Vessel Water Level - Low, Level 3 Allowable Value (LCO 3.3.6.1), 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 when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 11 valves.

Reactor Water Cleanup (RWCU) System Isolation

4.a - Reactor Vessel Water level - Low, Level 3

The definition of Drain Time allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level – Low (Level 3) Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System.

Reactor Vessel Water Level - Low, (Level 3) signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level – Low (Level 3) Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low (Level 3) Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level – Low (Level 3) Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened. The allowable value is referenced from a level of water 352.56 inches above thr lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref 6).

The Reactor Vessel Water Level – Low (Level 3) Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 5 valves.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to RPV Water Inventory Control 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 continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable RPV Water Inventory Control instrumentation channel.

A.1

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

B.1 and B.2

RHR System Isolation, Reactor Vessel Water Level - Low Level 3, and Reactor Water Cleanup System, Reactor Vessel Water Level - Low, Level 3 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating Drain Time. If the instrumentation is inoperable, Required Action B.1 directs an immediate declaration that the associated penetration flow path(s) are incapable of automatic isolation. Required Action B.2 directs calculation of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

C.1

Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. If the permissive is inoperable, manual initiation of ECCS is prohibited. Therefore, the permissive must be placed in the trip condition within 1 hour. With the permissive in the trip condition, manual initiation may be performed. Prior to placing the permissive in the tripped condition, the operator can take manual control of the pump and the injection valve to inject water into the RPV.

(continued)

BASES

ACTIONS

C.1 (continued)

The Completion Time of 1 hour is intended to allow the operator time to evaluate any discovered inoperabilities and to place the channel in trip.

D.1

If a Core Spray or Low Pressure Coolant Injection Pump Discharge Flow - Low bypass function is inoperable, there is a risk that the associated low pressure ECCS pump could overheat when the pump is operating and the associated injection valve is not fully open. In this condition, the operator can take manual control of the pump and the injection valve to ensure the pump does not overheat. If a manual initiation function is inoperable, the ECCS subsystem pumps can be started manually and the valves can be opened manually, but this is not the preferred condition.

The 24 hour Completion Time was chosen to allow time for the operator to evaluate and repair any discovered inoperabilities. The Completion Time is appropriate given the ability to manually start the ECCS pumps and open the injection valves and to manually ensure the pump does not overheat.

E.1

With the Required Action and associated Completion Time of Condition C or D not met, the associated low pressure ECCS injection/spray subsystem may be incapable of performing the intended function, and must be declared inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RPV Water Inventory Control instrument Function are found in the SRs column of Table 3.3.5.2-1.

SR 3.3.5.2.1

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 the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK guarantees that undetected outright channel failure is limited; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL FUNCTIONAL TEST. Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.
2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.
3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(F)," August 1992.
4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.
5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.
6. Drawing 11825-5.01-150. Rev. D. Reactor Assembly Nuclear Boiler (GE Drawing 9190690BO).

B 3.3 INSTRUMENTATION

B 3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

BASES

BACKGROUND

The purpose of the RCIC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is insufficient or unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level such that an initiation of the low pressure Emergency Core Cooling Systems (ECCS) pumps does not occur. A more complete discussion of RCIC System operation is provided in the Bases of LCO 3.5.3, "RCIC System."

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

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

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

(continued)

BASES

BACKGROUND (continued)

pool suction path must be open before the CST suction path automatically closes.

The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip (two-out-of-two logic), at which time the RCIC steam inlet valve closes. The RCIC System restarts if vessel level again drops to the low level initiation point (Level 2).

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safeguard System and no credit is taken in the safety analyses for RCIC System operation. The RCIC System instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 1). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the RCIC System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.3-1. Each Function must have a required number of OPERABLE channels with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

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

Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis or other appropriate documents. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

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

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

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

1. Reactor Vessel Water Level—Low Low (Level 2)

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

Reactor Vessel Water Level—Low Low (Level 2) signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level—Low Low (Level 2) Allowable Value is set high enough such that for complete loss of feedwater flow, the RCIC System flow with high pressure coolant injection assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Level 1. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 2).

The HPCI, RCIC and ATWS-RPT initiation functions (as described in Table 3.3.5.1-1, Function 3.a; Table 3.3.5.3-1, Function 1; and LCO 3.3.4.1.a including SR 3.3.4.1.4, respectively) describe the reactor vessel water level initiation function as "Low Low (Level 2)." The Allowable Values associated with the HPCI and RCIC initiation function is different from the Allowable Value associated with the ATWS-RPT initiation function as the ATWS function has a separate

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

analog trip unit. Nevertheless, consistent with the nomenclature typically used in design documents, the "Low Low (Level 2)" is

retained in describing each of these three initiation functions.

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

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

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

Reactor Vessel Water Level — High (Level 8) signals for RCIC are initiated from two level transmitters from the narrow range water level measurement instrumentation, which sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Both Level 8 signals are required in order to close the RCIC steam inlet valve.

The Reactor Vessel Water Level — High (Level 8) Allowable Value is high enough to preclude isolating the steam inlet valve during normal operation, yet low enough to prevent water overflowing into the MSLs. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 2).

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

3. Condensate Storage Tank (CST) Level — Low

Low level in the CSTs indicates the unavailability of an adequate supply of makeup water from this normal source. Normally, the suction valve between the RCIC pump and the CSTs is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3. Condensate Storage Tank (CST) Level — Low (continued)

taken from the CSTs. However, if the water level in both CSTs falls below a preselected level, first the suppression pool suction valves automatically open, and then the CSTs suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CSTs suction valve automatically closes.

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

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

4. Manual Initiation

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

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

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

(continued)

BASES (continued)

ACTIONS

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

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.3-1. The applicable Condition referenced in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

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

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to two inoperable, untripped Reactor Vessel Water Level—Low Low (Level 2) channels in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 3) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level—High (Level 8) Function whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation capability due to closure of the RCIC steam inlet valve. As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. This Condition also applies to the Manual Initiation Function. Since this Function is not assumed in any accident or transient analysis, a total loss of manual initiation capability (Required Action C.1) for 24 hours

is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in a safe state for the channel in all events.

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

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic component initiation capability being lost for the feature(s). For Required Action D.1, the RCIC System is the

(continued)

BASES

ACTIONS

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

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

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System suction source cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability (automatic suction source alignment) is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

E.1

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

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 2 and 4; and (b) for up to 6 hours for Functions 1 and 3, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

SR 3.3.5.3.1

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 parameter on other similar channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.3.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Progam. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.3.3 and SR 3.3.5.3.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3.4

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.5.3-1. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.3.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.36(c)(2)(ii).
2. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).
3. GENE-770-06-2-A, Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications, December 1992.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

BACKGROUND

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

The isolation instrumentation includes the sensors, logic circuits, relays, and switches that are necessary to cause initiation of primary containment and reactor coolant pressure boundary (RCPB) isolation. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logics are (a) reactor vessel water level, (b) main steam line (MSL) pressure, (c) MSL flow, (d) condenser vacuum, (e) main steam tunnel area temperatures, (f) main steam line radiation, (g) drywell pressure, (h) containment radiation, (i) high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) steam line flow, (j) HPCI and RCIC steam line pressure, (k) HPCI and RCIC turbine exhaust diaphragm pressure, (l) HPCI and RCIC area temperatures, (m) reactor water cleanup (RWCU) area temperature, (n) Standby Liquid Control (SLC) System initiation, and (o) reactor pressure. Redundant sensor input signals from each parameter are provided for initiation of isolation. The only exception is SLC System initiation.

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

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

(continued)

BASES

BACKGROUND

1. Main Steam Line Isolation (continued)

(MSIVs). The outputs from the same channels are arranged into two two-out-of-two logic trip systems to isolate all MSL drain valves. The MSL drain line has two isolation valves with one two-out-of-two logic system associated with each valve.

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

2. Primary Containment Isolation

The Reactor Vessel Water Level—Low (Level 3) and Drywell Pressure—High Primary Containment Isolation Functions (Functions 2.a and 2.b) receive inputs from four channels. Normally the outputs from these channels are arranged into two two-out-of-two logic trip systems. One trip system initiates isolation of all inboard primary containment isolation valves, while the other trip system initiates isolation of all outboard primary containment isolation valves. Each logic closes one of the two valves on each 2. Primary Containment Isolation penetration, so that operation of either logic isolates the penetration. The exception to this arrangement for the Reactor Vessel Water Level—Low (Level 3) and Drywell Pressure—High Functions (Functions 2.d and 2.g) are with certain penetration flow paths (i.e.,

(continued)

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BACKGROUND

2. Primary Containment Isolation (continued)

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

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

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

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

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

The exceptions are the HPCI and RCIC Turbine Exhaust Diaphragm Pressure—High, Steam Supply Line Pressure—Low, and the Equipment Area Temperature—High Functions (Functions 3.b through 3.j and 4.b through 4.f). These Functions receive inputs from four channels. The outputs from the turbine exhaust diaphragm pressure and steam supply pressure channels are each connected to two

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BACKGROUND

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

two-out-of-two trip systems. The output of each equipment area temperature channel is connected to one trip system so that any channel will trip its associated trip system. This arrangement is consistent with all other area temperature Functions, in that any channel will trip its associated trip system.

5. Reactor Water Cleanup System Isolation

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

6. Shutdown Cooling System Isolation

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

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BACKGROUND (continued)

7. Traversing Incore Probe System Isolation

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

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

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

Primary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

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

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis or other appropriate documents. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

Certain Emergency Core Cooling Systems (ECCS) and RCIC valves (e.g., minimum flow) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS and RCIC. The instrumentation requirements and ACTIONS associated with these signals are addressed in LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation," and LCO 3.3.5.3, "Reactor Core Isolation Cooling (RCIC) System Instrumentation," and are not included in this LCO.

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

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

Main Steam Line Isolation

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

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level—Low Low Low (Level 1) Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low Low (Level 1) Function

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

associated with isolation is assumed in the analysis of the recirculation line break (Ref. 2). The isolation of the MSLs on Level 1 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low Low Low (Level 1) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level — Low Low Low (Level 1) Allowable Value is chosen to ensure that the MSLs isolate on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 100 limits. In addition, the setting is low enough to allow the removal of heat from the reactor for a predetermined time following a scram, prevent isolation on a partial loss of feedwater and to reduce challenges to the safety/relief valves (S/RVs). The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

This Function isolates the MSIVs and MSL drain valves.

1.b. Main Steam Line Pressure — Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down at a rate greater than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure — Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 2). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below 785 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 25% RTP.)

The MSL low pressure signals are initiated from four transmitters that are connected to the MSL pressure averaging manifold. The transmitters are arranged such that, even though physically

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

separated from each other, each transmitter is able to detect low MSL pressure. Four channels of Main Steam Line Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

The Main Steam Line Pressure—Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 2). The Function is automatically bypassed when the reactor mode switch is not in the run position.

This Function isolates the MSIVs and MSL drain valves.

1.c. Main Steam Line Flow—High

Main Steam Line Flow—High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line

Flow—High Function is directly assumed in the analysis of the main steam line break (MSLB) (Ref. 3). The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 100 limits.

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

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break. In addition, the setting is high enough to permit the isolation of one main steam line at reduced power without causing an automatic isolation of the steam lines yet low

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

1.c. Main Steam Line Flow — High (continued)

enough to permit early detection of a gross steam line break.

This Function isolates the MSIVs and MSL drain valves.

1.d. Condenser Vacuum — Low

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

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser. Four channels of Condenser Vacuum — Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation, function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3 when all turbine stop valves (TSVs) are closed, since the potential for condenser overpressurization is minimized. The Function is automatically bypassed when the reactor mode switch is not in the run position and when all TSVs are closed.

This Function isolates the MSIVs and MSL drain valves.

1.e. Main Steam Tunnel Area Temperature — High

Main Steam Tunnel Area temperature is provided to detect a break in a main steam line and provides diversity to the high flow instrumentation. High temperature in the main steam tunnel outside the primary containment could indicate a break in a main steam line. The automatic closure of the MSIVs and MSL drains, prevents excessive loss of reactor coolant and the release of significant amounts of radioactive material from the reactor coolant pressure boundary. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the UFSAR, since bounding analyses are performed for large breaks, such as MSLBs.

Main Steam Tunnel Area temperature signals are initiated from resistance temperature detectors (RTDs) located in the area being monitored. Sixteen channels of Main Steam Tunnel Temperature — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen high enough above the temperature expected during power operations to avoid spurious isolation, yet low enough to provide early indication of a steam line break.

This Function isolates the MSIVs and MSL drain valves.

1.f. Main Steam Line Radiation — High

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

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

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

The Analytical Limit of 10.000 mr/hr was established by specific analysis to support use of a single trip setpoint for the Main Steam Line Radiation - High isolation signal. In accordance with the analysis. any setpoint less than the Analytical Limit provides assurance that the accident analysis remains bounding. This trip setpoint is dependent on general area background radiation levels near the

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

1.f. Main Steam Line Radiation—High (continued)

main steam lines. Since the setpoint cannot be calculated until specific plant conditions are established (i.e .• steady state 100% RTP with hydrogen injection in service), a period of time is required to establish and implement the newly calculated setpoints. since background radiation levels near the main steam lines may vary after each reactor core reload. After reaching the above conditions, forty eight hours is necessary for background radiation levels to stabilize to establish the steady state conditions of "normal full power background" and implement the corresponding trip setpoints. These new trip setpoints must be determined. verified and implemented within the forty eight hour time frame for the Main Steam Line Radiation - High instrumentation channels to remain OPERABLE.

This Function isolates the MSL drain valves.

Primary Containment Isolation

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

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level—Low (Level 3) Function associated with isolation is implicitly assumed in the UFSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level—Low (Level 3) signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. For Function 2.a, four channels of Reactor Vessel Water Level—Low (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. For Function 2.g, two channels of Reactor Vessel Water Level—Low (Level 3) are required to be OPERABLE for each hydrogen/oxygen and gaseous/particulate sample supply and return penetration to ensure these penetrations can be isolated.

The Reactor Vessel Water Level—Low (Level 3) Allowable Value was chosen to be the same as the RPS Level 3 scram Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

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

This Function isolates the valves listed in Reference 1.

2.b, 2.d. Drywell Pressure — High

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

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

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

These Functions isolate the valves listed in Reference 1.

2.c. Containment Radiation — High

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

The containment radiation signals are initiated from radiation detectors that are located in the drywell. Two channels of Containment Radiation — High Function are available and are

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APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

2.c. Containment Radiation—High (continued)

required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is low enough to promptly detect gross failures in the fuel cladding. However, the setting is high enough to avoid spurious isolation.

This Function isolates the containment vent and purge valves.

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

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the recirculation loop sample valves occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level—Low Low Low (Level 1) Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low Low (Level 1) Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 3). The isolation of the recirculation loop sample valves on Level 1 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low Low (Level 1) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

This Function isolates the recirculation loop sample valves.

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BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

2.f. Main Steam Line Radiation — High

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

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

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

The Analytical limit of 10.000 mr/hr was established by specific analysis to support use of a single trip setpoint for the Main Steam Line Radiation - High isolation signal. In accordance with the analysis. any setpoint less than the Analytical Limit provides assurance that the accident analysis remains bounding. This trip setpoint is dependent on general area background radiation levels near the main steam lines. Since the setpoint cannot be calculated until specific plant conditions are established (i.e., steady state 100% RTP with hydrogen injection in service) ,a period of time is required to establish and implement the newly calculated setpoints, since background radiation levels near the main steam lines may vary after each reactor core reload. After reaching the above conditions, forty eight hours is necessary for background radiation levels to stabilize to establish the steady state conditions of "normal full power background" and implement the corresponding trip setpoints. These new trip setpoints must be determined. verified and implemented within the forty eight hour time frame for the Main Steam Line Radiation· High instrumentation channels to remain OPERABLE.

This Function isolates the recirculation loop sample valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Isolation

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

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

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

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

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

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

Low steam pressure indicates that the pressure of the steam in the HPCI or RCIC turbine may be too low to continue operation of the associated system's turbine. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the UFSAR. However, they also provide a diverse signal to indicate a possible system break. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations (Ref. 5).

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3.b, 4.b. HPCI and RCIC Steam Supply Line Pressure—Low (continued)

The HPCI and RCIC Steam Supply Line Pressure—Low signals are initiated from transmitters (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both HPCI and RCIC Steam Supply Line Pressure—Low Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are selected to be high enough to prevent damage to the system's turbine and low enough to ensure HPCI and RCIC Systems remain OPERABLE.

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

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

High turbine exhaust diaphragm pressure could indicate that the turbine rotor is not turning, or there is a broken turbine blading or shrouding, thus allowing reactor pressure to act on the turbine exhaust line. The system is isolated to prevent overpressurization of the turbine exhaust line. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the UFSAR. These instruments are included in the TS because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations (Ref. 5).

The HPCI and RCIC Turbine Exhaust Diaphragm Pressure—High signals are initiated from switches (four for HPCI and four for RCIC) that are connected to the area between the rupture diaphragms on each system's turbine exhaust line. Four channels of both HPCI and RCIC Turbine Exhaust Diaphragm Pressure—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are high enough to prevent damage to low pressure components in the turbine exhaust pathway. The settings are adjusted low enough to avoid isolation of the system's turbine.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

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

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

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

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

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

Reactor Water Cleanup (RWCU) System Isolation

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

RWCU area temperatures are provided to detect a leak from the RWCU System. The isolation occurs even when very small leaks have occurred. If the small leak continues without isolation, offsite dose limits may be reached. Credit for these instruments is not taken in any transient or accident analysis in the UFSAR, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

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

The Area Temperature—High Allowable Values are set high enough to

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

5.a, 5.b, 5.c. RWCU Area Temperatures—High (continued)

avoid spurious isolation yet low enough to provide timely detection and isolation of a break in the RWCU System.

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

5.d. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 6). The RWCU isolation signal is initiated when the control room SLC initiation switch is in any position other than stop.

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

Two channels (start system A or start system B) of the SLC System Initiation Function are available and are required to be OPERABLE only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and MODE 3 for suppression pool pH control. These MODES are consistent with the Applicability for the SLC System (LCO 3.1.7).

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

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

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some interfaces with the reactor vessel occurs to isolate the potential sources of a break. The isolation of the RWCU System on Level 3 supports actions to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level—Low (Level 3) Function associated with RWCU isolation is not directly assumed in the UFSAR safety analyses because the RWCU System line break is bounded by breaks of larger systems (recirculation and MSL breaks are more limiting).

Reactor Vessel Water Level—Low (Level 3) signals are initiated from four level transmitters that sense the difference between the

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

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

5.f. Drywell Pressure — High

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

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

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

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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

6.a. Reactor Pressure — High

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

The Reactor Pressure — High signals are initiated from two transmitters that are connected to different condensing chambers. Each transmitter senses reactor pressure and provides input to each trip system. However, only one channel input is required to be OPERABLE for a trip system to be considered OPERABLE. Two channels of Reactor Pressure — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Function is only required to be OPERABLE in MODES 1, 2, and 3, since these are the only MODES in which the reactor can be pressurized; thus, equipment protection is needed.

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

This Function isolates both RHR shutdown cooling pump suction valves.

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

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level — Low (Level 3) Function associated with RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the reactor water recirculation system and MSL. The RHR Shutdown Cooling System isolation on Level 3 supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System.

Reactor Vessel Water Level — Low (Level 3) signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

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.

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

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

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

Traversing Incore Probe System Isolation

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

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level—Low (Level 3) Function associated with isolation is implicitly assumed in the UFSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level—Low (Level 3) signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Two channels of Reactor Vessel Water Level—Low (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The isolation function is

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

ensured by the manual shear valve in each penetration.

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

This Function isolates the TIP System isolation ball valves.

7.b Drywell Pressure—High

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

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

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

This Function isolates the TIP System isolation ball valves.

ACTIONS

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

(continued)

BASES

ACTIONS (continued)

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

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 2.a, 2.b, 2.d, 2.g, 5.e, 5.f, 6.b, 7.a and 7.b (which have components common to RPS) and 24 hours for Functions other than Functions 2.a, 2.b, 2.d, 2.g, 5.e, 5.f, 6.b, 7.a and 7.b has been shown to be acceptable (Refs. 6 and 7) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant isolation capability being lost for the associated penetration flow path(s). The MSL Isolation Functions (associated with MSIV isolation) are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip (or the associated trip system in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation functions are considered to be maintaining isolation

(continued)

BASES

ACTIONS

A.1 (continued)

capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that at least one of the PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For Functions 1.a, 1.b, and 1.d (associated with MSIV isolation), this would require both trip systems to have one channel OPERABLE or in trip. For Function 1.c (associated with MSIV isolation), this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip.

For Function 1.e, four areas are monitored by four channels (e.g., different locations within the main steam tunnel area). Therefore, this would require both trip systems to have one channel per location OPERABLE or in trip (associated with MSIV isolation). For Functions 1.a, 1.b, 1.d, and 1.f (associated with MSL drain isolation) this would require one trip system to have two channels, each OPERABLE or in trip. For Function 1.c (associated with MSL drain isolation) this will require one trip system to have two channels, associated with each MSL, each OPERABLE or in trip. For Function 1.e this would require one trip system to have two channels, associated with each main steam tunnel area, each to be OPERABLE or in trip. For Functions 2.d and 2.g, as noted by footnote (c) to Table 3.3.6.1-1, there is only one trip system provided for each associated penetration. For these penetrations (i.e., hydrogen/oxygen sample and return, and gaseous/particulate sample supply and return), this will require both channels to be OPERABLE or in trip in order to close at least one valve. For Functions 2.a, 2.b, 2.e, 2.f, 3.b, 3.c, 4.b, 4.c, 5.e, 5.f, and 6.b, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 2.c, 3.a, 3.d, 3.e, 3.f, 3.g, 3.h, 3.i, 4.a, 4.d, 4.e, 5.a, 5.c, and 6.a, this would require one trip system to have one channel OPERABLE or in trip. For Functions 3.j, 4.f, and 5.b each Function consists of channels that monitor two different locations. Therefore, this would require one channel per location to be OPERABLE or in trip (the channels are not required to be in the same trip system). For Function 5.d, this would require that with the SLC initiation switch in start system A or B the associated valve will close. For Function 7.a and 7.b the logic is arranged in one trip system, therefore this would require both channels to be OPERABLE or in trip, or the manual shear valves to be OPERABLE.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour

(continued)

BASES

ACTIONS

A.1 (continued)

Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

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

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). Alternately, the associated MSLs may be isolated (Required Action D.1), and, if allowed (i.e., plant safety analysis allows operation with one MSL isolated), operation with that MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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.

(continued)

BASES

ACTIONS (continued)

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken. The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to isolate the affected penetration flow path(s).

G.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. The 24 hour Completion Time is acceptable due to the fact the penetrations associated with these Functions (TIP System penetration) are a small bore (approx 1/2 inch), its isolation in a design basis event (with loss of offsite power) would be via the manually operated shear valves, and the ability to manually isolate by either the normal isolation valve or the shear valve is unaffected by the inoperable instrumentation.

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.

(continued)

BASES

ACTIONS (continued)

I.1 and I.2

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

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

J.1

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. Actions must continue until the channel is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

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

The Surveillances are modified by Note 2 to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours as follows: (a) for Functions 2.d, 2.g, 7.a, and 7.b; and (b) for Functions other than 2.d, 2.g, 7.a, and 7.b provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 7 and 8) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary. For Functions 2.d and 2.g, this allowance is permitted since the associated penetration flow path(s) involve sample lines which form a closed system with the primary containment atmosphere. For Functions 7.a and 7.b, this is permitted since the associated penetrations can be manually isolated if needed.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.1

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 the instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.6.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.3, SR 3.3.6.1.5, and SR 3.3.6.1.6

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions.

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

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.4

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.1.7

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

SR 3.3.6.1.8

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.8 (continued)

response time.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

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

B 3.3 INSTRUMENTATION

B 3.3.6.2 Secondary Containment Isolation Instrumentation

BASES

BACKGROUND

The secondary containment isolation instrumentation automatically initiates closure of appropriate secondary containment isolation valves (SCIVs), trips the refuel floor exhaust fans, trips the tank and equipment drain sump exhaust fan, and places the reactor building ventilation system in the recirculation mode of operation and starts the Standby Gas Treatment (SGT) System. The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation and establishment of vacuum with the SGT System within the required time limits ensures that fission products that leak from primary containment following a DBA, or are released outside primary containment, or are released during certain operations when primary containment is not required to be OPERABLE are maintained within applicable limits.

The isolation instrumentation includes the sensors, logic circuits, relays, and switches that are necessary to cause initiation of secondary containment isolation. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a secondary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (1) reactor vessel water level, (2) drywell pressure, (3) reactor building ventilation exhaust radiation, and (4) refueling floor ventilation exhaust radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation.

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

(continued)

BASES

BACKGROUND (continued)	starts one SGT subsystem, so that operation of either logic isolates the secondary containment and provides for the necessary filtration of fission products.
APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY	The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the LCO, andsafety analyses of References 1 and 2 to initiate closure of valves and start the SGT System to limit offsite and control room doses. Refer to LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," Applicable Safety Analyses Bases for more detail of the safety analyses. The secondary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3). The OPERABILITY of the secondary containment isolation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have the required number of OPERABLE channels with their setpoints set within the specified Allowable Values, as shown in Table 3.3.6.2-1. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Allowable Values are specified for each Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide (continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

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

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

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

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential for release of radioactive material and of the resulting offsite and control room dose. The Reactor Vessel Water Level — Low (Level 3) Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation systems on Reactor Vessel Water Level — Low (Level 3) support actions to ensure that any offsite releases are within the limits calculated in the safety analysis (Ref. 4).

Reactor Vessel Water Level — Low (Level 3) signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

The Reactor Vessel Water Level — Low (Level 3) Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

exists in the Reactor Coolant System (RCS); thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, this Function is not required.

2. Drywell Pressure — High

High drywell pressure can indicate a break in the reactor coolant pressure boundary (RCPB). An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite and control room release. The Drywell Pressure — High Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiating signals. The isolation and initiation systems on high drywell pressure supports actions to ensure that any offsite and control room releases are within the limits calculated in the safety analysis (Ref. 4).

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

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

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

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

High secondary containment exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a refueling accident. When Exhaust Radiation — High is detected, secondary containment isolation and

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

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

actuation of the SGT System are initiated to limit the release of fission products as assumed in the UFSAR safety analyses (Refs. 4 and 5).

The Exhaust Radiation — High signals are initiated from radiation detectors that are located on the ventilation exhaust piping coming from the reactor building and the refueling floor zones. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Ventilation Exhaust Radiation — High Function and two channels of Refueling Floor Ventilation Exhaust Radiation — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding and are set in accordance with the ODCM.

The Reactor Building and Refueling Floor Ventilation Exhaust Radiation — High Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable RCS energy exists; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, these Functions are not required. In addition, the Functions are also required to be OPERABLE during OPDRVs and movement of recently irradiated fuel assemblies in the secondary containment, because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery or dropped fuel assemblies) must be provided to ensure that offsite and control room dose limits are not exceeded. Due to radioactive decay, the Function is only required to isolate secondary containment during fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

ACTIONS

Note has been provided to modify the ACTIONS related to secondary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to

(continued)

BASES

ACTIONS (continued)

apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable secondary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable secondary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 1 and 2 (which have components common to RPS), and 24 hours for Functions 3 and 4, has been shown to be acceptable (Refs. 6 and 7) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a loss of isolation capability for the associated penetration flow path(s) or a loss of initiation capability for the SGT System. A Function is considered to be maintaining secondary containment isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two SCIVs in the associated penetration flow path and one SGT subsystem can be initiated on an isolation signal from the given Function. For the Functions with two two-out-of-two logic trip systems (Functions 1 and 2), this would require one trip system to have both channels OPERABLE or in trip. For Functions 3 and 4, this would require one trip system to have one OPERABLE or tripped channel.

(continued)

BASES

ACTIONS

B.1 (continued)

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

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

If any Required Action and associated Completion Time of Condition A or B are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the associated secondary containment penetration flow path(s) (closing the ventilation supply and exhaust automatic isolation dampers) and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operation to continue.

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

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

SURVEILLANCE REQUIREMENTS

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

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

This Note is based on the reliability analysis (Refs. 6 and 7) assumption of the average time required to perform channel surveillance. That analysis demonstrated the 6 hour testing

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

allowance does not significantly reduce the probability that the SCIVs will isolate the associated penetration flow paths and that the SGT System will initiate when necessary.

SR 3.3.6.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.6.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.3 and SR 3.3.6.2.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.2.4

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.2.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on SCIVs and the SGT System in LCO 3.6.4.2 and LCO 3.6.4.3, respectively, overlaps this Surveillance to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

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

B 3.3 INSTRUMENTATION

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

BASES

BACKGROUND	The CREVAS System is designed to provide a radiologically controlled environment to ensure the habitability of the control room for the safety of control room operators under all plant conditions. Two independent CREVAS subsystems are each capable of fulfilling the stated safety function. The instrumentation for the CREVAS System provides an alarm so that manual action can be taken to place the CREVAS System in the isolate mode of operation to pressurize the control room to minimize the infiltration of radioactive material into the control room environment. In the event of a Control Room Air Inlet Radiation—High signal, the CREVAS System is manually started in the isolate mode. Air is then drawn in from the air intake source and passes through one of two special filter trains each consisting of a prefilter, a high efficiency (HEPA) filter, two charcoal filters and a second HEPA filter. This air is then combined with recirculated air and directed to one of two control room ventilation fans and directed to the control room to maintain the control room slightly pressurized with respect to the adjacent areas. The CREVAS System instrumentation consists of a single trip system with one Control Room Air Inlet Radiation—High channel. The channel includes electronic equipment (e.g., detector, monitor and trip relay) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs to an alarm in the control room.
APPLICABLE SAFETY ANALYSIS	The ability of the CREVAS System to maintain the habitability of the control room is explicitly assumed for certain accidents as discussed in the UFSAR safety analyses (Refs. 1, 2, 3, and 4) and further discussed in Reference 5. CREVAS System operation ensures that the radiation exposure of control room personnel, through the duration of any one of the postulated accidents, does not exceed the limits set by GDC 19 of 10 CFR 50, Appendix A. CREVAS System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 6).

(continued)

BASES (continued)

LCO

The OPERABILITY of the CREVAS System instrumentation is dependent upon the OPERABILITY of the Control Room Air Inlet Radiation—High Function. This Function must have one OPERABLE channel, with its setpoint within the specified Allowable Value. The channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

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

The control room air inlet radiation monitor measures radiation levels in the inlet ducting of the control room. A high radiation level may pose a threat to control room personnel; thus, an alarm is provided in the control room sothat the CREVAS System can be placed in the isolate mode of operation.

(continued)

BASES (continued)

APPLICABILITY

The Control Room Air Inlet Radiation-High Function is required to be OPERABLE in MODES 1, 2, and 3 and during movement of recently irradiated fuel assemblies in the secondary containment, to ensure that control room personnel are protected during a LOCA or fuel handling event. During MODES 4 and 5, the probability of a LOCA is low: thus, the Function is not required. Also due to radioactive decay, the Function is only required to provide an alarm to alert the operator of the need to initiate the CREVAS System during fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

ACTIONS

A.1 and A.2

With the Control Room Air Inlet Radiation—High Function inoperable one CREVAS subsystem must be placed in the isolate mode of operation per Required Action A.1 to ensure that control room personnel will be protected in the event of a Design Basis Accident. Alternately, if it is not desired to start a CREVAS subsystem, the CREVAS System must be declared inoperable within 1 hour.

The 1 hour Completion Time is intended to allow the operator time to place the CREVAS subsystem in operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of the channel, for placing one CREVAS subsystem in operation, or for entering the applicable Conditions and Required Actions for two inoperable CREVAS subsystems.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the low probability of an event requiring this Function during this time period and since many other alarms are available to indicate whether a design basis event has occurred.

SR 3.3.7.1.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.1 (continued)

continues to operate properly between each CHANNEL CALIBRATION.

Channel agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.7.1.2

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.6.1.2.
2. UFSAR, Section 14.6.1.3.
3. UFSAR, Section 14.6.1.4.
4. UFSAR, Section 14.6.1.5.
5. UFSAR, Section 14.8.2.
6. 10 CFR 50.36(c)(2)(ii).

B 3.3 INSTRUMENTATION

B 3.3.7.2 Condenser Air Removal Pump Isolation Instrumentation

BASES

BACKGROUND

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

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

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

There are two isolation valves associated with this function.

APPLICABLE SAFETY ANALYSES

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

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

LCO

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

(continued)

BASES

LCO (continued)

system, with their setpoints within the specified Allowable Value of SR 3.3.7.2.2. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated isolation valve. Bases 3.3.6.1 for Functions 1.f and 2.f (Main Steam Line Radiation - High(provides additional information regarding the establishment of the trip setpoints.

An Allowable Value is specified for the Main Steam Line Radiation-High isolation Function in SR 3.3.7.2.2. A nominal trip setpoint is specified in the setpoint calculations. The nominal setpoint is selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (i.e., Main Steam Line Radiation-High), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limit is derived from the limiting values of the process parameters obtained from the safety analysis. The trip setpoint is derived from the analytical limit and accounts for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoint derived in this manner provides adequate protection because all expected uncertainties are accounted for. The Allowable Value is then derived from the trip setpoint by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties). The Allowable Value was selected to be low enough that a high radiation trip results from the fission products released in the CRDA. In addition, the setting is adjusted high enough above the background radiation level in the vicinity of the main steam lines so that spurious trips are avoided at rated power.

APPLICABILITY

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

(continued)

BASES

APPLICABILITY (continued)

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

ACTIONS

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

A.1 and A.2

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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

(Required Action A.1). Alternately, the inoperable channel, or associated trip system, may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable isolation valve, since this may not adequately compensate for the inoperable valve (e.g., the valve may be inoperable such that it will not isolate). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in loss of condenser vacuum), or if the inoperable channel is the result of an inoperable valve, Condition B must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels result in the Function not maintaining condenser air removal pump isolation capability. The Function is considered to be maintaining condenser air removal pump isolation capability when sufficient channels are OPERABLE or in trip such that the condenser air removal pump isolation instruments will generate a trip signal from a valid Main Steam Line Radiation–High signal, and at least one isolation valve will close. This requires one channel of the Function in each trip system to be OPERABLE or in trip, and one condenser air removal pump isolation valve to be OPERABLE.

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

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

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

(continued)

BASES

ACTIONS

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

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

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

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains condenser air removal pump isolation trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the condenser air removal pumps will isolate when necessary.

SR 3.3.7.2.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.1 (continued)

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

Channel agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of this LCO.

SR 3.3.7.2.2 and SR 3.3.7.2.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. SR 3.3.7.2.3, however, is only a calibration of the radiation detectors using a standard radiation source.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests.

As noted for SR 3.3.7.2.2, the main steam line radiation detectors are excluded from CHANNEL CALIBRATION due to ALARA reasons (when the plant is operating, the radiation detectors are generally in a high radiation area; the steam tunnel). This exclusion is acceptable because the radiation detectors are passive devices, with minimal drift.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.2 and SR 3.3.7.2.3 (continued)

The CHANNEL CALIBRATION of the remaining portions of the channel (SR 3.3.6.1.2) are performed using a standard current source.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.2.4

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.4.3.1.

2. UFSAR, Section 14.6.1.2.

3. 10 CFR 50.36(c)(2)(ii).

4. NEDC-31677P-A, Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation, July 1990.

B 3.3 INSTRUMENTATION

B 3.3.7.3 Emergency Service Water (ESW) System Instrumentation

BASES

BACKGROUND

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

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

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

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

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

LCO

The LCO requires four ESW instrumentation channels, which monitor the RBCLCW pump discharge header pressure, to be OPERABLE. The four channels provide input to both logic systems to ensure that no single instrument failure will prevent ESW from supplying the safe shutdown loads. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.7.3.1. The Allowable Value is set high enough to ensure logic initiation during a complete loss of the RBCLCW System and low enough to avoid logic initiation during small RBCLCW System pressure transients. The actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (i.e., RBCLCW pump discharge header pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., pressure switch) changes state. The analytic limit is derived from the limiting values of the process parameters obtained from the safety analysis or other appropriate documents. The trip setpoint is derived from the analytic limit and accounts for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Value is then derived from the trip setpoint by

(continued)

BASES

LCO (continued)

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

APPLICABILITY

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

ACTIONS

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

A.1

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

This out of service time is only acceptable provided the ESW pressure channels are still maintaining actuation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further

(continued)

BASES

ACTIONS

A.1 (continued)

restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an ESW System initiation), Condition C must be entered and its Required Action taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels result in redundant automatic initiation capability being lost for both ESW initiation logic systems. The ESW initiation logic systems are considered to be maintaining initiation capability when sufficient channels are OPERABLE or in trip such that one logic system will generate an initiation signal from the given Function on a valid signal. This will ensure that at least one ESW System will receive an initiation signal.

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

C.1

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

SURVEILLANCE REQUIREMENTS

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

SR 3.3.7.3.1

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with the applicable extensions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.3.2

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional test performed in LCO 3.7.2 overlaps this Surveillance to provide complete testing of the safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Chapter 5.
2. UFSAR, Chapter 14.
3. 10 CFR 50.36(c)(2)(ii).

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. The Main Generator (normal), the 115 kV transmission network (reserve), the 345 kV transmission network (backfeed) are the preferred sources of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from these power sources and connected to the onsite emergency diesel generator (EDG) power sources.

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

(continued)

BASES

BACKGROUND (continued)

The channels include electronic equipment (e.g., internal relay contacts, coils) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Accident analyses credit the loading of the EDGs based on the loss of the preferred power sources during a loss of coolant accident. The emergency diesel starting and loading times have been included in the delay time associated with each safety system component requiring EDG supplied power following a loss of the preferred power sources.

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

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

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

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

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

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while preferred power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. The Degraded Voltage Function is monitored via the secondary windings of two transformers associated with each emergency bus. Therefore, power supply to the bus is transferred from the preferred power source to onsite EDG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

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

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

(continued)

BASES (continued)

ACTIONS

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

A.1

With one or more channels of a Function inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure (within the LOP instrumentation), and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in an EDG initiation), Condition B must be entered and its Required Action taken.

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

B.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated EDG(s) is declared inoperable immediately. This requires

(continued)

BASES

ACTIONS

B.1 (continued)

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

SURVEILLANCE REQUIREMENTS

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

SR 3.3.8.1.1

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.1.2

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 8.6.5.
2. UFSAR, Section 6.4.
3. UFSAR, Section 14.6.
4. 10 CFR 50.36(c)(2)(ii).

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

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

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

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

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

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

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and its alternate power supply. Each of these circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing

(continued)

BASES

BACKGROUND (continued)

logic constitute an electric power monitoring assembly. If the output of the inservice MG set or alternate power supply exceeds predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

APPLICABLE SAFETY ANALYSES

The RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS buses can perform its intended function. RPS electric power monitoring provides protection to the RPS and other systems that receive power from the RPS buses, by acting to disconnect the RPS from the power supply under specified conditions that could damage the RPS bus powered equipment.

RPS electric power monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

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

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2 and SR 3.3.8.2.3). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual

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BASES

LCO (continued)

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

The Allowable Values for the instrument settings are based on the RPS providing ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V ± 10 V (to scram pilot valve solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the buses and RPS MG set or alternate power supply being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS components from the inservice MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a non-class 1E source supplying power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies is required when the RPS bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1 and 2; and in MODES 3, 4, and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

A.1

If one RPS electric power monitoring assembly for an inservice power supply (MG set or alternate) is inoperable, or one RPS electric power monitoring assembly on each

(continued)

BASES

ACTIONS

A.1 (continued)

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

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

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

B.1

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

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BASES

ACTIONS

B.1 (continued)

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

C.1

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

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 3, 4, or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Required Action D.1 results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. All actions must continue until the applicable Required Actions are completed.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1 (continued)

is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.2.2 and SR 3.3.8.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.2.4

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated electric power monitoring assembly. The system functional test shall include actuation of the protective relays, tripping logic, and output circuit breakers. Only one signal per electric power monitoring

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.4 (continued)

assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 8.9.5.

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

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

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

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

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BASES

BACKGROUND (continued)

reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the void negative reactivity effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 65% to 100% of RTP) without having to move control rods and disturb desirable flux patterns. The recirculation flow also provides sufficient core flow to ensure thermal-hydraulic stability of the core is maintained.

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

APPLICABLE SAFETY ANALYSES

The operation of the Reactor Water Recirculation System is an initial condition assumed in the design basis loss of coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Ref. 1). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in the loop with the higher flow. While the flow coastdown and core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable based on engineering judgement. The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 14 of the UFSAR.

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe

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BASES

APPLICABLE SAFETY ANALYSES (continued)

break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Ref. 3).

The transient analyses of Chapter 14 of the UFSAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System (RPS) average power range monitor (APRM) and the control rod block instrumentation Allowable Values are also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR limits for single loop operation are specified in the COLR. The APRM Neutron Flux–High (Flow Biased) Allowable Value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." The Rod Block Monitor–Upscale Allowable Value is specified in LCO 3.3.2.1, "Control Rod Block Instrumentation."

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

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BASES

APPLICABLE SAFETY ANALYSES (continued)

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

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

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

LCO

Two recirculation loops are required to be in operation with their flows matched within the limits specified in SR 3.4.1.2 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. With the limits specified in SR 3.4.1.2 not met, the recirculation loop with the lower flow must be considered not in operation. With only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), APRM Neutron Flux – High (Flow Biased) Allowable Value (LCO 3.3.1.1) and the Rod Block Monitor – Upscale Allowable Value (LCO 3.3.2.1) must be applied to allow continued operation consistent with the assumptions of Reference 3. In addition, during two-loop and single-loop operation, the combination of core flow and THERMAL POWER must be outside the Exclusion Region of the power-to-flow map specified in the COLR to ensure core thermal-hydraulic instability does not occur.

APPLICABILITY

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

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BASES

APPLICABILITY (continued)

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

ACTIONS

A.1

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

B.1

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

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

(continued)

BASES

ACTIONS

B.1 (continued)

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

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

C.1

With any Required Action and associated Completion Time of Condition A or B not met, or no recirculation loop is in operation, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the combination of core flow and THERMAL POWER are within appropriate limits to prevent uncontrolled thermal-hydraulic oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal-hydraulic instability. The power-to-flow map specified in the COLR is based on guidance provided in Reference 7. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

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

SR 3.4.1.2

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

The mismatch is measured in terms of percent of rated core flow. If the flow mismatch exceeds the specified limits, Condition B must be entered, and the loop with the lower flow must be declared "not in operation". (However, for the purpose of performing SR 3.4.1.1, the flow rate of both loops shall be used.) The SR is not required when only one loop is in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.6.
2. UFSAR, Section 14.5.
3. NEDO-24281, FitzPatrick Nuclear Power Plant Single-Loop Operation, August 1980.
4. UFSAR, Section 16.6.
5. NEDO-31960-A, BWR Owners' Group Long Term Stability Solutions Licensing Methodology, June 1991.

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BASES

REFERENCES (continued)

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

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

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

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

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

Each reactor coolant recirculation loop contains 10 jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

APPLICABLE SAFETY ANALYSES

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

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and

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BASES

APPLICABLE SAFETY ANALYSES (continued)

performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

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

LCO

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

APPLICABILITY

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

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

ACTIONS

A.1

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

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 3). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 3 and 4). Each recirculation loop must satisfy one of the performance criteria provided. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, recirculation loop jet pump flow, and recirculation pump flow, these relationships may need to be re-established each cycle. Jet Pump OPERABILITY is considered acceptable prior to startup of the plant following a refueling outage due to acceptable results obtained during the previous operating cycle, or by visual inspection of the jet pumps. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns", engineering judgement of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

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

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SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

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

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

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

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

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

REFERENCES

1. UFSAR, Section 14.6.

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

3. GE Service Information Letter No. 330, including Supplement 1, Jet Pump Beam Cracks, June 9, 1980.

4. NUREG/CR-3052, Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure, November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code (Ref. 1) requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

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

The S/RVs can actuate by either of two modes: the safety mode or the relief mode. However, for the purposes of this LCO, only the safety mode is required. As pressure increases, the expanding bellows pulls the connecting rod attached to the pilot disk, eliminating an abutment gap between the rod and disk. At the valve set pressure, the disk lifts off the seat and pressure is ported to the second stage piston chamber. The force on the piston pushes the second stage disk off of its seat. Opening the second stage valve allows a pressure differential to develop across the main valve piston and opens the main valve. This satisfies the Code requirement.

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS

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

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

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

LCO

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

The single nominal S/RV setpoint is established (Ref. 2) to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The single nominal S/RV setpoint is set below the RPV design pressure (1250 psig) in accordance with ASME Code requirements. The transient evaluations in Reference 5 are based on this single setpoint, but also include the additional uncertainties of ± 3% of the nominal setpoint to provide an added degree of conservatism.

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

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, nine S/RVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.

ACTIONS

A.1 and A.2

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

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance requires that the required S/RVs open at the pressures assumed in the safety analysis of References 3 and 4. The demonstration of the S/RV safety function lift settings must be performed during shutdown, since this is a bench test, to be done in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The S/RV setpoint is ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.3.2

Valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code requirements, prior to valve installation. Actuation of each required S/RV is performed to verify that mechanically the valve is functioning properly. This requires that the pilot stage be tested to show that it actuates when required and opens the associated main stage. Likewise, the main stage must be tested to show that it opens and passes steam when the associated pilot stage actuates. The actuators and main stages are bench tested, together or separately, as part of the certification process, at intervals determined in accordance with the Inservice Testing Program. Maintenance procedures ensure that the S/RV actuators and main stages are correctly installed in the plant, and that the S/RV and associated piping remain clear of foreign material that might obstruct valve operation or full steam flow. This approach provides adequate assurance that the required S/RVs will operate as required, while minimizing the challenges to the S/RVs and the likelihood of leakage or spurious operation.

For the purpose of this test, pilot actuation in the safety mode or relief mode is acceptable to satisfy the test requirements. Testing of the related solenoid valves is not required because they do not affect the safety mode operation of the S/RV. However, the solenoid valves are also tested in the IST program to support relief mode operation of the S/RVs for other functions.

REFERENCES

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.2 (continued)

the safety mode operation of the S/RV. However, the solenoid valves are also tested in the IST program to support relief mode operation of the S/RVs for other functions.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.

2. UFSAR, Section 4.4.

3. UFSAR, Section 14.5.1.2.

4. UFSAR, Section 16.9.3.2.3.

5. UFSAR, Section 14.5.2.

6. 10 CFR 50.36(c)(2)(ii).

7. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted. Some joints in ≤ 1 inch piping are also threaded.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and UFSAR, Section 16.6 (Refs. 1, 2, and 3).

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

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

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

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests that, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

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

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

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

RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 7).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

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

b. Unidentified LEAKAGE

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

(continued)

BASES

LCO (continued)

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE which may be detected by the drywell equipment drain sump monitoring system). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

d. Unidentified LEAKAGE Increase

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

APPLICABILITY

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

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

ACTIONS

A.1

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

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the LEAKAGE rate such that the current rate is less than the "2 gpm increase in the previous 24 hours" limit; either by isolating the source or other possible methods) is to evaluate service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type of piping is very susceptible to IGSCC.

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

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, any method may be used to quantify LEAKAGE within the guidelines of Reference 8.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

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

Limits are established on abnormal leakage so that corrective action can be taken before unacceptable results occur (Ref. 4). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. The Bases for LCO 3.4.4, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

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

LEAKAGE from the RCPB inside the drywell is detected by at least one of two independently monitored variables, such as sump pump flow and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in the floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Reactor Building Closed Loop Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The drywell floor drain sump has instrumentation that supply level indicators in the control room.

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

(continued)

BASES

BACKGROUND (continued)

increase in leak rate) an alarm annunciates in the control room.

As the water which has been collected in the drywell floor drain sump is pumped out, the discharge flow is measured and total flow indicated by a flow integrator. The unidentified LEAKAGE and unidentified LEAKAGE increase are periodically calculated from this flow integrator. A flow recorder continually plots time versus discharge flow rate: an increase in leakage rate is also detectable by an increase in sump discharge flow time and an increased frequency in discharge flow cycles.

The drywell continuous atmospheric monitoring system continuously monitors the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell atmosphere particulate and gaseous radioactivity monitoring system is not capable of quantifying LEAKAGE rates. The sensitivity and response time of the system are a function of: location of the leak; amount of fission or corrosion product remaining in the atmosphere where they may be measured; plateout of these products in the sampling lines; effectiveness of the drywell coolers in reducing airborne concentrations; and the power level at the time of leakage occurrence (Ref. 3). The drywell continuous atmospheric particulate monitoring system is sufficiently sensitive to detect a reactor coolant leak of 1 gpm within 4 hours. The drywell continuous atmospheric gaseous monitoring system, however, will not alarm for reactor coolant leaks (since there is no retention factor for noble gases in the reactor coolant). The drywell continuous atmospheric gaseous monitoring system will respond only if the leak is in the steam portion of the RCPB. Larger changes in LEAKAGE rates can be detected in proportionally shorter times (Ref. 5).

APPLICABLE SAFETY ANALYSIS

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 6 and 7). Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm or indication of excess LEAKAGE in the control room.

A control room alarm or indication allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Refs. 6 and 7). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

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

LCO

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

APPLICABILITY

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

ACTIONS

A.1

With the drywell floor drain sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell continuous atmospheric monitors will provide indication of changes in leakage.

With the drywell floor drain sump monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 4 hours (SR 3.4.4.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

(continued)

BASES

ACTIONS (continued)

B.1

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

C.1 and C.2

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

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

D.1 and D.2

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

E.1

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

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the other required instrumentation (the drywell floor drain sump monitoring system or drywell continuous atmospheric monitoring channel, as applicable) is OPERABLE. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring RCS leakage.

SR 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required drywell continuous atmospheric monitoring channels. The check gives reasonable confidence that the channels are operating properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument channel. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.3

This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument channel. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Specific Activity

BASES

BACKGROUND

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

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure that in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100.11 (Ref. 1).

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

APPLICABLE SAFETY ANALYSES

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

This MSLB release forms the basis for determining offsite and control room doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 100. The limits on the specific activity of the primary coolant also ensure the thyroid dose to the control room operators, resulting from an MSLB outside containment during steady state operation will not exceed the limits specified in GDC 19 of 10 CFR 50, Appendix A (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

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

APPLICABILITY

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

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

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 2.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

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

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ 0.2 μCi/gm within 48 hours, or if at any time it is > 2.0 μCi/gm, it must be determined at least once every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 100.11 and GDC 19 of 10 CFR 50 Appendix A (Ref. 3) during a postulated MSLB accident.

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

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the plant in MODES 3 and 4 are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

(continued)

BASES (continued)

REFERENCES

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 Residual Heat Removal (RHR) Shutdown Cooling System – Hot Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature of the reactor coolant to ≤ 212°F in preparation for performing Refueling or Cold Shutdown maintenance operations, or the decay heat must be removed for maintaining the reactor in the Hot Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems (loops) of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same reactor water recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated reactor water recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System (LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System").

APPLICABLE SAFETY ANALYSES

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

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both RHR pumps (and two RHR service water pumps) in one loop or one RHR pump (and one RHR service water pump) in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (from the control

(continued)

BASES

LCO (continued)

room or locally) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

The Note allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR shutdown cooling subsystem in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR shutdown cooling subsystems or other operations requiring loss of redundancy.

APPLICABILITY

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

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

(continued)

BASES

APPLICABILITY (continued)

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

ACTIONS

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

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

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

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

(continued)

BASES

ACTIONS

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

cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

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

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

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR shutdown cooling flow path provides assurance that the proper flow paths will exist for RHR operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that can be manually (from the control room or locally) aligned is allowed to be in a non-RHR shutdown cooling position provided the valve can be repositioned. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1 (continued)

This Surveillance is modified by a Note allowing sufficient time to verify RHR shutdown cooling subsystem OPERABILITY after clearing the pressure interlock that isolates the system. The Note takes exception to the requirements of the Surveillance being met (i.e., valves are aligned or can be aligned is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

REFERENCES

1. UFSAR, Chapter 14.

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant ≤ 212°F in preparation for performing refueling operations, or the decay heat must be removed for maintaining the reactor in the Cold Shutdown condition.

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

APPLICABLE SAFETY ANALYSES

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

LCO

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

(continued)

BASES

LCO (continued)

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

The Note allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR shutdown cooling subsystems in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR shutdown cooling subsystems or other operations requiring loss of redundancy.

APPLICABILITY

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

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

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

(continued)

BASES

APPLICABILITY (continued)

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

ACTIONS

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

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, except as permitted by the LCO Note, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to)

(continued)

BASES

ACTIONS

A.1 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR shutdown cooling flow path provides assurance that the proper flow paths will exist for RHR operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that can be manually (from the control room or locally) aligned is allowed to be in a non-RHR shutdown cooling position provided the valve can be repositioned. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 14.

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

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

BASES

BACKGROUND

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

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

Each P/T limit curve defines an acceptable region for normal operation. The curves are used for operational guidance during heatup or cooldown maneuvering. Pressure and temperature are monitored and compared to the applicable curve to ensure that operation is within the allowable region.

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

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

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

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

(continued)

BASES

BACKGROUND (continued)

with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4), and the BWR Vessel and Internals Project (VIP) Integrated Surveillance Program (ISP) (Ref.13). The operating P/T limit curves are adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 5.

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

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

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

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

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. Reference 14 establishes the methodology for determining the P/T limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

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

LCO

The elements of this LCO are:

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

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is within the limits of the PTLR during recirculation pump startup;

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is within the limits of the PTLR during recirculation pump startup;

d. RCS pressure and temperature are within the limits specified in the PTLR, prior to achieving criticality; and

e. The reactor vessel flange and the head flange temperatures are within the limits specified in the PTLR when tensioning the reactor vessel head bolting studs and when any stud is tensioned.

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

(continued)

BASES

LCO (continued)

The limits on the rate of change of RCS temperature, influenced by RCS flow and RCS stratification, control the thermal gradient through the vessel wall. For this reason, both RCS temperature and RPV metal temperatures are used as inputs for calculating the heatup, cooldown, and inservice leakage and hydrostatic testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

P/T limit curves are provided for plant operations through 40 EFPY in the PTLR. Curve A establishes the minimum temperature for hydrostatic and leak testing, Curve B establishes limits for plant heatup and cooldown when the reactor is not critical or during low power physics tests, and Curve C establishes the limits when the reactor is critical. In addition, ART is the adjusted reference temperature.

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

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

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

c. The existence, size, and orientation of flaws in the vessel material.

APPLICABILITY

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

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

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

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

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

The 72 hour Completion Time is reasonable to accomplish the engineering evaluation of a mild violation. A mild violation is one which is technically acceptable because it is bounded by an existing evaluation or one which reasonably can be expected to be found acceptable following evaluation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

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

B.1 and B.2

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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

reduced pressure and temperature. With the reduced pressure and temperature conditions, the likelihood of propagation of undetected flaws is decreased.

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

C.1 and C.2

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

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

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

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within the PTLR limits is required when RCS pressure and temperature conditions are undergoing planned changes. This

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 (continued)

is accomplished by monitoring the bottom head drain, recirculation loop, and RPV metal temperatures. The limits in the PTLR are met when operation is on or to the right of the applicable curve. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

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

SR 3.4.9.2

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

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

SR 3.4.9.3, SR 3.4.9.4, and SR 3.4.9.5

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

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

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

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

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

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

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

SR 3.4.9.6, SR 3.4.9.7, and SR 3.4.9.8

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations when any reactor vessel head bolting stud is tensioned with RCS

(continued)

BASES

SURVEILLANCE REQUIREMENTS

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

temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits within 30 minutes before and while tensioning the reactor vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When any reactor vessel head bolting stud is tensioned with RCS temperature ≤ 80°F, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When any reactor vessel head bolting stud is tensioned with RCS temperature ≤ 100°F, monitoring of the flange temperature is required every 12 hours to ensure the temperature is within specified limits.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.9.6 is modified by a Note which requires the SR to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.7 is modified by a Note which states that the SR is not required to be performed until 30 minutes after RCS temperature is ≤ 80°F in MODE 4. SR 3.4.9.8 is modified by a Note which states that the SR is not required to be performed until 12 hours after RCS temperature is ≤ 100°F in MODE 4. These Notes are necessary to specify when the reactor vessel flange and head flange temperatures are required to be within specified limits.

REFERENCES

1. 10 CFR 50, Appendix G.

2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

3. ASTM E 185-82, July 1982.

4. 10 CFR 50, Appendix H.

5. Regulatory Guide 1.99, Revision 2, Radiation Embrittlement of Reactor Vessel Materials, May 1988.

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

(continued)

BASES

REFERENCES (continued)

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

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

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

10. UFSAR, Section 14.5.7.2.

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

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

13. UFSAR, Section 4.2.7.

14. SIR-05-044-A, “Pressure-Temperature Limits Report Methodology For Boiling Water Reactors”, dated June 2013.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.1 ECCS—Operating

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network consists of the High Pressure Coolant Injection (HPCI) System, the Core Spray (CS) System, the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System, and the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the condensate storage tanks (CSTs), they are capable of providing a source of water for the HPCI and CS systems.

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

Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool is circulated through a heat exchanger cooled by the RHR Service Water System. Depending on the location and size of the break, portions of the

(continued)

BASES

BACKGROUND (continued)

ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break.All low pressure ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS equipment.

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of a motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal if preferred power is available, the CS pumps in both subsystems will automatically start after a time delay of approximately 11 seconds. If a CS initiation signal is received when preferred power is not available, the CS pumps start approximately 11 seconds after the associated bus is energized by the emergency diesel generators (EDGs). When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water to the suppression pool to allow testing of the CS System without spraying water in the RPV.

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

(continued)

BASES

BACKGROUND (continued)

or C) to ensure the other EDG in the same EDG subsystem is not overloaded. RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the recirculation loops. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the corresponding recirculation loop, begins. The water then enters the reactor through the jet pumps. A full flow test line is provided for each LPCI subsystem to route water from the suppression pool, to allow testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling."

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from both CSTs and the suppression pool. Pump suction for HPCI is normally aligned to both CSTs to minimize injection of suppression pool water into the RPV. However, if the water supply is low in both CSTs, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System and ensures the containment loads do not exceed design values. The steam supply to the HPCI turbine is piped from the "C" main steam line upstream of the inboard main steam isolation valve.

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

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valve in the HPCI line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. The minimum flow

(continued)

BASES

BACKGROUND (continued)

bypass valves for the LPCI and CS pumps are normally open for the same purpose. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, all ECCS pump discharge lines are filled with water. The LPCI and CS System discharge lines are kept full of water using a "keep full" system (jockey pump system). The HPCI System is normally aligned to the CSTs. The height of water in the CSTs is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for HPCI is such that the water in the feedwater lines keeps the remaining portion of the HPCI discharge line full of water. Therefore, HPCI does not require a "keep full" system.

The ADS (Ref. 4) consists of 7 of the 11 S/RVs. It is designed to provide depressurization of the RCS during a small break LOCA if HPCI fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (CS and LPCI), so that these subsystems can provide coolant inventory makeup. Each of the S/RVs used for automatic depressurization is equipped with one air accumulator and associated inlet check valves. The accumulator provides the pneumatic power to actuate the valves. One of the ADS valves shares an accumulator with a non-ADS valve.

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 5, 6, and 7. The required analyses and assumptions are defined in Reference 8. The results of these analyses are also described in Reference 9.

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

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

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

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

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 5. For a LOCA due to a large recirculation pump suction line pipe break, failure of the Division 2 125 VDC battery is considered the most severe failure. For a small break LOCA, HPCI failure is the most severe failure. In the analysis of events requiring ADS operation, it is assumed that only five of the seven ADS valves operate. Since six ADS valves are required to be OPERABLE, the explicit assumption of the failure of an ADS valve is not considered in the analysis. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 11).

LCO

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

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

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually

(continued)

BASES

LCO (continued)

realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the system is being realigned from or to the RHR shutdown cooling mode. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

The HPCI system is considered OPERABLE when it is aligned to the suppression pool or to one or both CSTs with power available to support automatic realignment to the suppression pool if required. This is based on the design of the CSTs and the accident analysis which credits the suppression pool for supplying the HPCI System.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. Requirements for MODES 4 and 5 are specified in LCO 3.5.2, "RPV Water Inventory Control."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI System. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI System 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.

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable or if one LPCI pump in both LPCI subsystems is inoperable, the inoperable subsystem(s) must be restored to OPERABLE status within

(continued)

BASES

ACTIONS

A.1 (continued)

7 days. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single active component failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is consistent with the recommendations provided in a reliability study (Ref. 12) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1 and B.2

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

C.1 and C.2

If the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY immediately is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified, however, Condition G must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is consistent with the recommendations provided in a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

D.1 and D.2

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

E.1

The LCO requires six ADS valves to be OPERABLE in order to provide the ADS function. Reference 5 contains the results of an analysis

(continued)

BASES

ACTIONS

E.1 (continued)

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

F.1 and F.2

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

G.1 and G.2

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

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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

H.1

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

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCI System, CS System, and LPCI subsystems full of water ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are full is to vent at the high points and observe water flow through the vent. Another acceptable method is to verify that the associated "keep full" level switch alarms are clear. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a non-accident position provided the valve will

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

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

The intent of this surveillance is to ensure the availability of required flow paths. The operation of the HPCI system is supported by flow paths from one or both CSTs and the suppression pool. Therefore, it is permissible to isolate a single CST by repositioning manual isolation valves without considering this SR not met. This is permissible based on the design of the CSTs and the administrative controls on plant configuration.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.3

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

SR 3.5.1.4

Verification every that the RHR System cross tie valves are closed and power to the motor operated valve is disconnected ensures that each LPCI subsystem remains independent and a failure of the flow path in one subsystem will not affect the flow path of the other LPCI subsystem. Acceptable methods of removing power to the operator include de-energizing breaker control power or racking out or removing the breaker. If one or more of the RHR System cross tie valves are open or power has not been removed from the motor operated valve, both LPCI subsystems must be considered inoperable. In addition, plant procedures require the motor operated cross tie valve to be chain-locked closed and the manual cross tie valve to be locked closed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.5

Verification every that each LPCI inverter output has a voltage of ≥ 576 V and ≤ 624 V while supplying its respective bus

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

demonstrates that the AC electrical power is available to ensure proper operation of the associated LPCI injection and heat exchanger bypass valves and the recirculation pump discharge valve. Each inverter must be OPERABLE for the associated LPCI subsystem to be OPERABLE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.6

Cycling the recirculation pump discharge valves through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will close when required. Upon initiation of an automatic LPCI subsystem injection signal, these valves are required to close to ensure full LPCI subsystem flow injection in the reactor via the recirculation jet pumps. De-energizing the valve in the closed position will also ensure the proper flow path for the LPCI subsystem. Acceptable methods of de-energizing the valve include de-energizing breaker control power, racking out the breaker or removing the breaker.

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

SR 3.5.1.7, SR 3.5.1.8, and SR 3.5.1.9

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 8). This periodic Surveillance is performed (in accordance with

(continued)

BASES

SURVEILLANCE REQUIREMENTS

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

the ASME Code, Section XI, requirements for the ECCS pumps) to verify that the ECCS pumps will develop at least the flow rates required by the respective analyses. The low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 10. The pump flow rates are verified against a system head equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during a LOCA. These values may be established during preoperational testing. The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested at both the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these tests. Adequate reactor steam pressure must be ≥ 970 psig to perform SR 3.5.1.8 and > 150 psig to perform SR 3.5.1.9. Adequate steam flow is represented by at least one turbine bypass valve open or main turbine generator load is greater than 100 MWe. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that HPCI is inoperable.

Therefore, SR 3.5.1.8 and SR 3.5.1.9 are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

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

perform the test. The 12 hours allowed for performing the flow test after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides reasonable time to complete the SRs.

The Frequency for SR 3.5.1.7 and SR 3.5.1.8 is in accordance with the Inservice Testing Program requirements. The Frequency for SR 3.5.1.9 is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.10

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. The HPCI System actual or simulated automatic actuation test must be performed with adequate steam pressure for verification of automatic pump startup. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Thus, sufficient time is allowed after adequate pressure and flow are achieved to perform this test associated with the HPCI System. Adequate reactor steam dome pressure is > 150 psig. Adequate steam flow is represented by at least one turbine bypass valve open. This SR also ensures that the HPCI System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip. In addition, this SR also ensures that the HPCI suction is automatically

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.10 (continued)

transferred from the CSTs to the suppression pool on high suppression pool water level or low CST water level. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 states that for the HPCI System, the Surveillance is not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for performing the actual or simulated automatic actuation for the HPCI System after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides reasonable time to complete the SR. Note 2 excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.11

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.11 (continued)

an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.13 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that excludes valve actuation since the valves are individually tested in accordance with SR 3.5.1.13. This prevents the possibility of an RPV pressure blowdown.

SR 3.5.1.12

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.13

Valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code requirements, prior to valve installation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.13 (continued)

Actuation of each required ADS valve is performed to verify that mechanically the valve is functioning properly. The tests are required to demonstrate:

- That each ADS S/RV solenoid valve ports pneumatic pressure to the associated S/RV actuator when energized;
- That each ADS S/RV pilot stage actuates to open the associated main stage when the pneumatic actuator is pressurized; and
- That each ADS S/RV main stage opens and passes steam when the associated pilot stage actuates.

The solenoid valves are functionally tested once per cycle as part of the Inservice Testing Program. The actuators and main stages are bench tested, together or separately, as part of the certification process, at intervals determined in accordance with the Inservice Testing Program. Maintenance procedures ensure that the S/RV actuators and main stages are correctly installed in the plant, and that the S/RV and associated piping remain clear of foreign material that might obstruct valve operation or full steam flow. This approach provides adequate assurance that the required ADS valves will operate when actuated, while minimizing the challenges to the valves and the likelihood of leakage or spurious operation. The two-stage actuator assemblies are not tested in-situ due to a high probability of causing unseating or leakage of the pilot stage which can lead to spurious actuation or failure to reclose. SR 3.5.1.11 and the LOGIC SYSTEM FUNCTIONAL Test performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

(continued)

BASES

REFERENCES

1. UFSAR, Section 6.4.3.

2. UFSAR, Section 6.4.4.

3. UFSAR, Section 6.4.1.

4. UFSAR, Section 6.4.2.

5. NEDC-31317P, Revision 2, James A. FitzPatrick Nuclear Power Plant SAFER/GESTR-LOCA, Loss-of-Coolant Accident Analysis, April 1993.

6. UFSAR, Section 14.6.1.5.

7. UFSAR, Section 14.6.1.3.

8. 10 CFR 50, Appendix K.

9. UFSAR, Section 6.5.

10. 10 CFR 50.46.

11. 10 CFR 50.36(c)(2)(ii).

12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), Recommended Interim Revisions to LCOs for ECCS Components, December 1, 1975.

13. UFSAR, Section 4.4.5.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control

BASES

BACKGROUND

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.1.3 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

APPLICABLE SAFETY ANALYSIS

With the unit in MODE 4 or 5, RPV water inventory control is not SAFETY required to mitigate any events or accidents evaluated in the safety ANALYSES analyses. RPV water inventory control is required in MODES 4 and 5 to protect Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material to the environment should an unexpected draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not postulated in MODES 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which single operator error or initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (e.g., seismic event, loss of normal power, single human error). It is assumed, based on engineering judgment, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The RPV water level must be controlled in MODES 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by Safety Limit 2.1.1.3.

The Limiting Condition for Operation (LCO) requires the DRAIN TIME of RPV water inventory to the TAF to be ≥ 36 hours. A DRAIN TIME of 36 hours is considered reasonable to identify and initiate action to mitigate unexpected draining of reactor coolant. An event that could cause loss of RPV water inventory and result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.1.3 and can be managed as part of normal plant operation.

One low pressure ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually started to provide defense-indepth should an unexpected draining event occur. A low pressure ECCS injection/spray subsystem consists of either one Core Spray (CS) subsystem or one Low Pressure Coolant Injection (LPCI) subsystem. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. In MODES 4 and 5, the RHR System cross tie valve is not required to be closed.

The LCO is modified by a Note which allows a required LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of the restrictions on DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TAF.

(continued)

BASES (continued)

APPLICABILITY

RPV water inventory control is required in MODES 4 and 5. Requirements on water inventory control in other MODES are contained in LCOs in Section 3.3, Instrumentation, and other LCOs in Section 3.5, ECCS, RCIC, and RPV Water Inventory Control. RPV water inventory control is required to protect Safety Limit 2.1.1.3 which is applicable whenever irradiated fuel is in the reactor vessel.

ACTIONS

A.1 and B.1

If the required low pressure ECCS injection/spray subsystem is inoperable, it must be restored to OPERABLE status within 4 hours. In this Condition, the LCO controls on DRAIN TIME minimize the possibility that an unexpected draining event could necessitate the use of the ECCS injection/spray subsystem, however the defense-in-depth provided by the ECCS injection/spray subsystem is lost. The 4 hour Completion Time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considers the LCO controls on DRAIN TIME and the low probability of an unexpected draining event that would result in loss of RPV water inventory.

If the inoperable ECCS injection/spray subsystem is not restored to OPERABLE status within the required Completion Time, action must be initiated immediately to establish a method of water injection capable of operating without offsite electrical power. The method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The method of water injection may be manually initiated and may consist of one or more systems or subsystems, and must be able to access water inventory capable of maintaining the RPV water level above the TAF for ≥ 36 hours. If recirculation of injected water would occur, it may be credited in determining the necessary water volume.

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

With the DRAIN TIME less than 36 hours but greater than or equal to 8 hours, compensatory measures should be taken to ensure the ability to implement mitigating actions should an unexpected draining event occur. Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

(continued)

BASES

ACTIONS (continued)

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

The secondary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Required Action C.1 requires verification of the capability to establish the secondary containment boundary in less than the DRAIN TIME. The required verification confirms actions to establish the secondary containment boundary are preplanned and necessary materials are available. The secondary containment boundary is considered established when one Standby Gas Treatment (SGT) subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

Verification that the secondary containment boundary can be established must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment. Secondary containment penetration flow paths form a part of the secondary containment boundary. Required Action C.2 requires verification of the capability to isolate each secondary containment penetration flow path in less than the DRAIN TIME. The required verification confirms actions to isolate the secondary containment penetration flow paths are preplanned and necessary materials are available. Power operated valves are not required to receive automatic isolation signals if they can be closed manually within the required time. Verification that the secondary containment penetration flow paths can be isolated must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Required Action C.3 requires verification of the capability to place one SGT subsystem in operation in less than the DRAIN TIME. The required verification confirms actions to place a SGT subsystem in operation are preplanned and necessary materials are available. Verification that a SGT subsystem can be placed in operation must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

(continued)

BASES

ACTIONS (continued)

D.1, D.2, D.3, and D.4

With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur. Note that if the DRAIN TIME is less than 1 hour, Required Action E.1 is also applicable.

Required Action D.1 requires immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by the LCO. The additional method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The Note to Required Action D.1 states that either the ECCS injection/spray subsystem or the additional method of water injection must be capable of operating without offsite electrical power. The additional method of water injection may be manually initiated and may consist of one or more systems or subsystems. The additional method of water injection must be able to access water inventory capable of being injected to maintain the RPV water level above the TAF for ≥ 36 hours. The additional method of water injection and the ECCS injection/spray subsystem may share all or part of the same water sources. If recirculation of injected water would occur, it may be credited in determining the required water volume.

Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

The secondary containment provides a control volume in which fission products can be contained, diluted, and processed prior to release to the environment. Required Action D.2 requires that actions be immediately initiated to establish the secondary containment boundary. With the secondary containment boundary established, one SGT subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

The secondary containment penetrations form a part of the secondary containment boundary. Required Action D.3 requires that actions be immediately initiated to verify that each secondary containment penetration flow path is isolated or to verify that it can be manually isolated from the control room.

(continued)

BASES

ACTIONS

D.1, D.2, D.3, and D.4 (continued)

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Required Action D.4 requires that actions be immediately initiated to verify that at least one SGT subsystem is capable of being placed in operation. The required verification is an administrative activity and does not require manipulation or testing of equipment.

E.1

If the Required Actions and associated Completion times of Conditions C or D are not met or if the DRAIN TIME is less than 1 hour, actions must be initiated immediately to restore the DRAIN TIME to ≥ 36 hours. In this condition, there may be insufficient time to respond to an unexpected draining event to prevent the RPV water inventory from reaching the TAF. Note that Required Actions D.1, D.2, D.3, and D.4 are also applicable when DRAIN TIME is less than 1 hour.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

This Surveillance verifies that the DRAIN TIME of RPV water inventory to the TAF is ≥ 36 hours. The period of 36 hours is considered reasonable to identify and initiate action to mitigate draining of reactor coolant. Loss of RPV water inventory that would result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.1.3 and can be managed as part of normal plant operation.

The definition of DRAIN TIME states that realistic cross-sectional areas and drain rates are used in the calculation. A realistic drain rate may be determined using a single, step-wise, or integrated calculation considering the changing RPV water level during a draining event. For a Control Rod RPV penetration flow path with the Control Rod Drive Mechanism removed and not replaced with a blank flange, the realistic cross-sectional area is based on the control rod blade seated in the control rod guide tube. If the control rod blade will be raised from the penetration to adjust or verify seating of the blade, the exposed crosssectional area of the RPV penetration flow path is used.

The definition of DRAIN TIME excludes from the calculation those penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are locked, sealed, or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

otherwise secured in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths. A blank flange or other bolted device must be connected with a sufficient number of bolts to prevent draining in the event of an Operating Basis Earthquake. Normal or expected leakage from closed systems or past isolation devices is permitted. Determination that a system is intact and closed or isolated must consider the status of branch lines and ongoing plant maintenance and testing activities.

The Residual Heat Removal (RHR) Shutdown Cooling System is only considered an intact closed system when misalignment issues (Reference 6) have been precluded by functional valve interlocks or by isolation devices, such that redirection of RPV water out of an RHR subsystem is precluded. Further, RHR Shutdown Cooling System is only considered an intact closed system if its controls have not been transferred to Remote Shutdown, which disables the interlocks and isolation signals.

The exclusion of penetration flow paths from the determination of DRAIN TIME must consider the potential effects of a single operator error or initiating event on items supporting maintenance and testing (rigging, scaffolding, temporary shielding, piping plugs, snubber removal, freeze seals, etc.). If failure of such items could result and would cause a draining event from a closed system or between the RPV and the isolation device, the penetration flow path may not be excluded from the DRAIN TIME calculation.

Surveillance Requirement 3.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME requires that a new DRAIN TIME be determined.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.2 and SR 3.5.2.3

The minimum water level of 10.33 ft required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CS subsystem or LPCI subsystem pump, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, the required ECCS injection/spray subsystem is inoperable unless aligned to an OPERABLE CST.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.2 and SR 3.5.2.3 (continued)

The required CS System is OPERABLE only if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CS pump. Therefore, a verification that either the suppression pool water level is ≥ 10.33 ft or that a required CS subsystem is aligned to take suction from the CST and the CST contains ≥ 354,000 gallons (two tanks) of water, equivalent to 324 inches (27 ft), ensures that the CS subsystem can supply at least 50,000 gallons of makeup water to the RPV. The CS suction is uncovered at the 258,000 gallon (two tanks) level.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.4

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the required ECCS injection/spray subsystems full of water ensures that the ECCS subsystem will perform properly. This may also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are full is to vent at the high points.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.5

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.6

Verifying that the required ECCS injection/spray subsystem can be manually started and operate for at least 10 minutes demonstrates that the subsystem is available to mitigate a draining event. Testing the ECCS injection/spray subsystem through the recirculation line is necessary to avoid overfilling the refueling cavity. The minimum operating time of 10 minutes was based on engineering judgement.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.7

Verifying that each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated RPV water level isolation signal is required to prevent RPV water inventory from dropping below the TAF should an unexpected draining event occur.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.8

The required ECCS injection/spray subsystem shall be capable of being manually operated from the Control Room. This Surveillance verifies that the required CS or LPCI subsystem (including the associated pump and valve(s)) can be manually operated to provide additional RPV water inventory, if needed.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

(continued)

BASES (continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.
2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.
3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f), " August 1992.
4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.
5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.
6. General Electric Service Information Letter No. 388, "RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6," February 1983.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

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

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

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping is provided from the condensate storage tanks (CSTs) and the suppression pool. Pump suction is normally aligned to the CSTs to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from the "B" main steam line upstream of the associated inboard main steam line isolation valve.

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

(continued)

BASES

BACKGROUND (continued)	The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge piping is kept full of water. The RCIC System is normally aligned to the CSTs. The height of water in the CSTs is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for RCIC is such that the water in the feedwater lines keeps the remaining portion of the RCIC discharge line full of water. Therefore, RCIC does not require a "keep full" system.
APPLICABLE SAFETY ANALYSES	The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safeguard System and no credit is taken in the safety analyses for RCIC System operation. The RCIC System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).
LCO	The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the low pressure ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity for maintaining RPV inventory during an isolation event. The RCIC system is considered OPERABLE when it is aligned to the suppression pool or to one or both CSTs with power available to support automatic realignment to the suppression pool if required. This is based on the design of the CSTs and the RCIC System.
APPLICABILITY	The RCIC System is required to be OPERABLE during MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig, since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, the low pressure ECCS injection/spray subsystem can provide sufficient flow to the RPV. In MODES 4 and 5, RCIC is not required to be OPERABLE since RPV water inventory control is required by LCO 3.5.2, “RPV Water Level Inventory Control.”

(continued)

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable RCIC System. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable RCIC System 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.

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of HPCI is therefore verified immediately when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is consistent with the recommendations in a reliability study (Ref. 4) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of similar functions of HPCI and RCIC, the AOTs (i.e., Completion Times) determined for HPCI are also applied to RCIC.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the Reactor Coolant System upon demand. This will also prevent a water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high points and observe water flow through the vent. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program

SR 3.5.3.2

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.2 (continued)

require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The intent of this surveillance is to ensure the availability of required flow paths. The operation of the RCIC system is supported by flow paths from one or both CSTs and the suppression pool. Therefore, it is permissible to isolate a single CST by repositioning manual isolation valves without considering this SR not met. This is permissible based on the design of the CSTs and the administrative controls on plant configuration.

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested both at the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the main turbine or turbine

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.3 and 3.5.3.4 (continued)

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

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.3.5

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.5 (continued)

automatic initiation logic of the RCIC System will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence; that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) signal (Level 8 signal closes RCIC steam inlet valve, and subsequent Level 2 signal will re-open valve) and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed design function.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

This SR is modified by Note 2 that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 16.6.

2. UFSAR, Section 4.7.

3. 10 CFR 50.36(c)(2)(ii).

4. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), Recommended Interim Revisions to LCOs for ECCS Components, December 1, 1975.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material. The primary containment consists of the drywell (a steel pressure vessel in the shape of an inverted light bulb) and the suppression chamber (a steel pressure vessel in the shape of a torus) located below and encircling the drywell. The primary containment surrounds the Reactor Coolant System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment.

The isolation devices for the penetrations in the primary containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. The primary containment air lock is OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks"; and

c. All equipment hatches are closed.

This Specification ensures that the performance of the primary containment, in the event of a Design Basis Accident (DBA), meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are specified in the Primary Containment Leakage Rate Testing Program which is in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

(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 Loss of Coolant Accident (LOCA). In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

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

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

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time the applicable leakage limits must be met. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

Individual leakage rates for the primary containment air locks are addressed in LCO 3.6.1.2 and specified in the Primary Containment Leakage Rate Testing Program.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of

(continued)

BASES

APPLICABILITY (continued)

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

ACTIONS

A.1

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

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet the air lock leakage limit (SR 3.6.1.2.1), or the main steam isolation valve leakage limit (SR 3.6.1.3.10) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. Failure to meet the Low Pressure Coolant Injection (LPCI) or Core Spray (CS)System injection line air operated testable check valve leakage limit (SR 3.6.1.3.11) does not result in failure of this SR since the LPCI and CS testable check valve leakage is not included in the Primary Containment Leakage Rate Testing Program limits (Ref. 5 and 6).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1 (continued)

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

SR 3.6.1.1.2

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR is a leak test that confirms that the bypass area between the drywell and suppression chamber is less than the equivalent of a one inch diameter plate orifice (Ref. 1). This ensures that the leakage paths that would bypass the suppression pool are within allowable limits (i.e., ≤ 71 scfm).

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the suppression chamber (≥ 1 psi)and verifying that the pressure in the suppression chamber does not increase by more than 0.25 inches of water per minute over a 10 minute period. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Two consecutive test failures, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 12 months is required until the situation is remedied as evidenced by passing two consecutive tests.

REFERENCES

1. UFSAR, Section 5.2.

2. UFSAR, Section 14.6.1.3.

3. 10 CFR 50, Appendix J, Option B.

(continued)

BASES

REFERENCES (continued)

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

5. License Amendment 40, dated November 9, 1978.

6. License Amendment 234, dated October 4, 1996.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Locks

BASES

BACKGROUND

Two double door primary containment air locks (personnel access hatch and emergency escape hatch) have been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entry and exit. The air locks are designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment (Ref. 1). As part of the primary containment, the air locks limit the release of radioactive material to the environment during normal plant operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

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

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

The primary containment air locks form part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining the primary containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the plant safety analysis.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The postulated DBA that results in the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The maximum allowable leakage rate (L_a) for the primary containment is 1.5% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 45 psig (Primary Containment Leakage Rate Testing Program). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

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

The primary containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

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

The primary containment air locks are required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from primary containment.

APPLICABILITY

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

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary containment boundary is not intact (during access through the OPERABLE outer door). The allowance to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed .

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

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

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

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

(continued)

BASES

ACTIONS

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

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

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

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

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities inside primary containment that are required by TS or activities that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. The required administrative controls consist of stationing a dedicated individual to assure closure of

(continued)

BASES

ACTIONS

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

the OPERABLE door except during the entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

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

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

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

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

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

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in an air lock have

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BASES

ACTIONS

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

failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed) primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

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

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

D.1 and D.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were approved in License Amendment 97 (Ref. 3). Subsequently, License Amendment 261 (Ref. 4) allowed an increased overall air lock leakage rate (i.e., Amendment 261 increased the value of L_a; therefore, the overall air lock

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

leakage rate limit value that corresponds to 0.05 L_a increased). The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

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

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure (Ref. 1), closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES (continued)

REFERENCES

1. UFSAR, Section 5.2.

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

3. NRC letter dated November 21, 1985, Issuance of Amendment 97 to the Facility Operating License DPR-59 for James A. FitzPatrick Nuclear Power Plant.

4. NRC letter dated April 21, 2000, Issuance of Amendment 261 to the Facility Operating License DPR-59 for James A. FitzPatrick Nuclear Power Plant.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

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

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

The reactor building-to-suppression chamber vacuum breakers serve a dual function, one of which is primary containment isolation. However, since the other safety function of the vacuum breakers would not be available if the normal PCIV actions were taken, the PCIV OPERABILITY requirements are not applicable to the reactor building-to-suppression chamber vacuum breakers valves. Similar surveillance requirements in the LCO for reactor building-to-suppression chamber vacuum breakers provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

The primary containment suppression chamber and drywell vent and purge lines are 20 and 24 inches in diameter respectively, and are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. The isolation valves on

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BASES

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSIS

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

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a LOCA, control rod drop accident, and a main steam line break (MSLB). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or close within the required isolation times following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment vent and purge valves) are minimized. Of the events analyzed in Reference 1 for which the consequences are mitigated by PCIVs, the MSLB is the most limiting event due to radiological consequences to control room personnel. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds, after signal generation, since the 3 second closure time is assumed in the MSIV closure analysis (Ref. 2) and the 5 second closure time is consistent with or conservative to the times assumed in the MSLB analyses (Refs. 3 and 4). Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

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BASES

APPLICABLE SAFETY ANALYSIS (continued)

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

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

PCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 7).

LCO

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

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. The 20 and 24 inch vent and purge valves must be maintained closed or blocked to prevent full opening. While the reactor building-to-suppression chamber vacuum breakers isolate primary containment penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.1.6, "Reactor Building-to-Suppression Chamber Vacuum Breakers." The valves covered by this LCO are listed in Reference 8. The associated stroke time of each automatic PCIV is included in the Inservice Testing (IST) Program.

The normally closed PCIVs are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 8.

MSIVs, Low Pressure Coolant Injection (LPCI) and Core Spray (CS) System air operated testable check valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

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, PCIVs are not required to be OPERABLE and the primary containment vent and purge valves are not required to be normally closed in MODES 4 and 5. Certain valves, however, are required to be OPERABLE when the 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.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

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

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or 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 or more PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

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

B.1

With one or more penetration flow paths with two or more PCIVs inoperable except for inoperabilities due to MSIV leakage or LPCI or CS System air operated testable check valve leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active component failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

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

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable except for inoperabilities due to MSIV leakage or LPCI or CS System air operated testable check valve leakage not within limits, the inoperable valve must be restored to OPERABLE status or the affected

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active component failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 72 hours for penetrations with a closed system is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The closed system must meet the requirements of Reference 9. The Completion Time of 72 hours for EFCVs is also reasonable considering the instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. This Required Action does not require any testing or device manipulation. Rather, it involves verification, that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

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

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

D.1

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

E.1

With the one or more penetration flow paths with LPCI System or CS System air operated testable check valve leakage rate not within limits, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 72 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, or closed manual valve. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 72 hour Completion Time is reasonable considering the time required to restore the leakage and the importance to maintain these penetrations available to perform the required function during a design basis accident.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

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

G.1 and G.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required to OPERABLE during MODE 4 or 5, the plant must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to restore the valve(s) to OPERABLE status. This allows RHR shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR ensures that the primary containment vent and purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that the SR is not required to be met when the vent and purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open, provided the full-flow 12 inch line (with valve 27MOV-120) to the SGT System is closed and one or more SGT System reactor building suction valves are open. This will ensure there is no damage to the filters if a LOCA were to occur with the vent and purge valves open since excessive differential pressure is not expected with the full-flow 12 inch line closed and one or more SGT System reactor building suction valves open. The 20 and 24 inch vent and purge valves are capable of closing against the dynamic effects of a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.2

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

This SR does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside primary containment, and capable of being mispositioned, are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

SR 3.6.1.3.3

This SR ensures that each primary containment manual isolation valve and blind flange that is located inside primary containment and not locked, sealed or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For isolation devices inside primary containment, the Frequency defined as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

92 days" is appropriate since these isolation devices are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.5

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.6

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

SR 3.6.1.3.7

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.8

This SR requires a demonstration that each reactor instrumentation line excess flow check valve (EFCV) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break. This SR provides assurance that the instrumentation line EFCVs will perform so that secondary containment will not be overpressurized during the postulated instrument line break (Ref. 10). The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.9

The TIP shear isolation valves are actuated by explosive charges. An in-place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.10

The analyses in Reference 11 are based on leakage that is more than the specified leakage rate. The combined main steam line leakage rate must be ≤ 200 scfh when tested at ≥ 25 psig. The leakage limit for a single main steam line is ≤ 100 scfh when tested at ≥ 25 psig. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is in accordance with the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.3.11

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

REFERENCES

1. UFSAR, Section 14.6.
2. UFSAR, Section 14.5.2.3.
3. UFSAR, Section 6.5.3.2.
4. UFSAR, Section 14.8.2.1.2.
5. UFSAR, Section 7.3.3.1.
6. UFSAR, Table 7.3-1.
7. 10 CFR 50.36(c)(2)(ii).
8. Technical Requirements Manual.
9. UFSAR, Section 5.2.3.5.
10. UFSAR, Section 16.3.2.5.
11. UFSAR, Section 14.8.2.1.1.
12. NRC Letter to NYPA, November 9, 1978 NRC Safety Evaluation Supporting Amendment 40 to the Facility Operating License No. DPR-59.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND

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

APPLICABLE SAFETY ANALYSIS

Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Refs. 1, 2, 3, and 4). Analyses assume an initial drywell pressure of 1.95 psig. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell internal pressure does not exceed the drywell design pressure of 56 psig.

The maximum calculated drywell pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak drywell pressure for this limiting event is 43.1 psig (Ref. 4).

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

LCO

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

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell pressure within limits is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A.1

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

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

Verifying that drywell pressure is within limit ensures that plant operation remains within the limit assumed in the primary containment analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1 UFSAR, Section 14.6.1.3.3.

2 NEDO-24578, Revision 0, Mark I Containment Program Plant Unique Load Definition, James A. FitzPatrick Nuclear Power Plant, March 1979.

3 UFSAR, Section 16.9.3.5.

4 005N1724, “James A. FitzPatrick Nuclear Power Plant Short-Term Containment Analysis for Zero Drywell-to-Wetwell Pressure Differential,” Rev. 0, May 2019.

5 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND	The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in the Reference 1 safety analyses.
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for a spectrum of break sizes for postulated loss of coolant accidents (LOCAs) (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature (Refs. 1 and 2). Analyses assume an initial average drywell air temperature of 135°F. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature and pressure do not exceed the drywell design pressure of 56 psig coincident with a design temperature of 309°F (Ref. 3). Exceeding these design limitations may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment required to mitigate the effects of a DBA is designed to operate and be capable of operating under environmental conditions expected for the spectrum of break sizes. Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).
LCO	In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature and pressure are maintained within the drywell design limits and within the environmental qualification envelope of the equipment in the drywell. As a result, the ability of primary containment to perform its design function is ensured.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are

(continued)

BASES

APPLICABILITY (continued)

reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.

ACTIONS

A.1

With drywell average air temperature not within the limit of the LCO, drywell average air temperature must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems.

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

REFERENCES

1. UFSAR, Section 14.6.1.3.3.

2. GE-NE-T23-00737-01, James A. FitzPatrick Nuclear Power Plant Higher RHR Service Water Temperature Analysis, August 1996.

3. UFSAR, 16.7.3.2.3.

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

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the reactor building-to-suppression chamber vacuum relief system consists of four vacuum breakers (two parallel sets of 100% capacity vacuum breaker pairs, each set consisting of a self-actuating vacuum breaker and an air operated vacuum breaker), located in two lines. The air operated vacuum breakers are actuated by differential pressure switches and can be remotely operated from the relay room. The self-actuating vacuum breakers function similar to a check valve. The two vacuum breakers in series must be closed to maintain a leak tight primary containment boundary.

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

The reactor building-to-suppression chamber vacuum breakers are sized to mitigate any depressurization transient and limit the maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Suppression chamber-to-drywell and reactor building-to-suppression chamber vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls, which form part of the primary containment boundary.

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

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

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

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

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

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

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

LCO

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

(continued)

BASES

LCO (continued)

vacuum breaker) will open to relieve a negative pressure in the suppression chamber. This LCO also ensures that the two vacuum breakers in each of the two lines from the reactor building to the suppression chamber airspace are closed (except during testing or when performing their intended function).

APPLICABILITY

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

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

ACTIONS

A Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path.

A.1

With one or more lines with one vacuum breaker not closed, the leak tight primary containment boundary may be threatened. Therefore, the inoperable vacuum breakers must be restored to OPERABLE status or the open vacuum breaker closed within 72 hours. The 72 hour Completion Time is consistent with requirements for inoperable suppression-chamber-to-drywell vacuum breakers in LCO 3.6.1.7, "Suppression-Chamber-to-Drywell Vacuum Breakers." The 72 hour Completion Time takes into account the redundant capability afforded by the remaining breakers, the fact

(continued)

BASES

ACTIONS

A.1 (continued)

that the OPERABLE breaker in each of the lines is closed, and the low probability of an event occurring that would require the vacuum breakers to be OPERABLE during this period.

B.1

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

C.1

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

D.1

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

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

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

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

SR 3.6.1.6.2

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. The Frequency of this SR is in accordance with the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.6.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.6.4

Demonstration of each self-actuating vacuum breaker opening setpoint is necessary to ensure that the design function regarding vacuum breaker opening differential pressure of ≤ 0.5 psid is valid. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

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

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

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 5 external vacuum breakers located on the external lines connecting the top of the suppression chamber with drywell vent pipes, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. Each vacuum breaker is a self-actuating valve, similar to a check valve, which can be manually operated locally for testing purposes.

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

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

In addition, the waterleg in the Mark I Vent System downcomers are controlled by the drywell-to-suppression chamber differential pressure. If the drywell pressure is less than the suppression chamber pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing inertia in the event of a postulatedLOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads.

(continued)

BASES

BACKGROUND (continued)

The suppression chamber-to-drywell vacuum breakers may limit the height of the waterleg in the vent system during time periods when drywell-to-suppression chamber differential pressure is not positive.

APPLICABLE SAFETY ANALYSIS

Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are used as part of the accident analyses of the primary containment systems. Suppression chamber-to-drywell and reactor building-to-suppression chamber vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls that form part of the primary containment boundary.

The safety analyses assume that the suppression chamber-to-drywell vacuum breakers are closed initially and start to open at a differential pressure of 0.5 psid (Refs. 1 and 2). Additionally, 1 of the 5 vacuum breakers is assumed to fail in a closed position (Ref. 1). The results of the analyses show that the design differential pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that all vacuum breakers be OPERABLE (the additional vacuum breaker is required to meet the single failure criterion) are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. The cross sectional areas of the vacuum breakers are sized on the basis of the Bodega Bay pressure suppression system tests. The vacuum breaker capacity selected on this test basis is more than adequate to limit the pressure differential between the suppression chamber and drywell during post-accident drywell cooling operations to a value which is within the suppression system design values (Refs. 3 and 4). Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and to remain closed and leak tight, until the suppression pool is at a positive pressure relative to the drywell.

The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

(continued)

BASES (continued)

LCO

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

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside the drywell could also occur due to inadvertent actuation of the RHR Containment Spray System during normal operation.

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

ACTIONS

A.1

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

(continued)

BASES

ACTIONS (continued)

B.1

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

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Each vacuum breaker is verified closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing local or relay room vacuum breaker position indication or by performing SR 3.6.1.1.2, the bypass leakage test. If the bypass test fails, not only must the vacuum breaker(s) be considered open and the appropriate Conditions and Required Actions of this LCO be entered, but also the appropriate Condition and Required Actions of LCO 3.6.1.1 must be entered. Each suppression chamber-to-drywell vacuum breaker disc will be seated as long as the arm movement is ≤ 1.0 degree. The vacuum breakers are considered closed if the associated position light indicates the closed position since it is set to actuate at ≤ 1.0 degree. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1 (continued)

Two Notes are added to this SR. The first Note allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers.

The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.7.3

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker opening differential pressure of 0.5 psid is valid. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1 UFSAR, Section 14.6.1.3.3.

2 UFSAR, Section 5.2.3.6.

3 UFSAR, Section 5.2.4.2.

4 Preliminary Hazards Summary Report, Bodega Bay Atomic Park Unit Number 1, Docket No. 50-205, Appendix I, December 28, 1962.

5 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Deleted

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.9 Residual Heat Removal (RHR) Containment Spray System

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single active failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the suppression chamber airspace, bypassing the suppression pool. The RHR Containment Spray System is designed to mitigate the effects of bypass leakage and to prevent the drywell temperature from exceeding its design value of 309°F (Ref. 1) for a significant period of time and to ensure the safety equipment can perform its associated function during a design basis event.

There are two redundant, 100% capacity RHR containment spray subsystems. Each subsystem consists of a suction line from the suppression pool, two RHR pumps, a heat exchanger, and its associated spray header embedded in and protected by the primary shield wall located in the drywell and to a common spray header suspended in the suppression chamber above the minimum water level.

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

APPLICABLE SAFETY ANALYSES

Reference 2 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area. The analyses determined that for a range of reactor coolant system break and bypass leakage areas, containment spray operation would terminate the primary

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment pressure rise. For larger break or bypass leakage areas, sufficient time would be available to allow manual reactor depressurization to terminate the primary containment pressure rise. As reactor break size increases further, the vessel depressurizes through the break and containment response is essentially unaffected by bypass leakage area.

Steam line breaks have been analyzed to develop a drywell air temperature history for use in equipment qualification (Refs. 3 and 4). The RHR containment sprays were assumed to be initiated 10 minutes following a main steam line break. The RHR containment spray flow rates were assumed to be 7150 gpm for drywell sprays and 600 gpm for suppression chamber sprays. The highest air temperature envelope is 335°F for the first 300 seconds and this is a result of a 0.75 ft^2 steam line break (Ref. 4). The analysis concluded containment design temperature is not exceeded since drywell spray activation will terminate any further rise in drywell air temperature. Subsequent analysis (Ref. 7) determined that containment spray flow rates as low as 7500 gpm with 5600 gpm supplied to the drywell and 1900 gpm supplied to the suppression chamber would successfully mitigate steam line breaks and maintain containment pressure and temperature within the environmental qualification envelopes.

The RHR Containment Spray System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

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

APPLICABILITY

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

(continued)

BASES (continued)

ACTIONS

A.1

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

B.1

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

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR containment spray mode flow path provides assurance that the proper flow paths will exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1 (continued)

also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable since the RHR Containment Spray System is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.9.2

Verifying each required RHR pump develops a flow rate ≥ 7750 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. It is tested in the pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in the drywell. Flow is a normal test of centrifugal pump performance required by the ASME Code, Section XI (Ref. 6). This test confirms one point on the pump performance curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.9.3

This Surveillance is performed by introduction of air to verify that the spray nozzles are not obstructed and that flow will be provided when required. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued

BASES (continued)

REFERENCES

1. UFSAR, Table 5.2-1.

2. UFSAR, Section 5.2.4.4.

3. UFSAR, Section 14.6.

4. GE-NE-T23-00737-01, James A. FitzPatrick Nuclear Power Plant Higher RHR Service Water Temperature Analysis, August 1996.

5. 10 CFR 50.36(c)(2)(ii).

6. ASME, Boiler and Pressure Vessel Code, Section XI.

7. JAF-RPT-06-00063, Rev. 0, Drywell Spray Flow Rate Design and Licensing Bases, September 19, 2006.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

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

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

a. Complete steam condensation;

b. Primary containment peak pressure and temperature;

c. Condensation oscillation loads; and

d. Chugging loads.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool temperature. (Reference 1 for LOCAs and References 2 and 3 for the pool temperature analyses required by Reference 4). An initial pool temperature of 95°F is assumed for the References 1, 2, and 3 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool temperature of 120°F were cases addressed as part of the pool temperature analyses of Reference 2. The limiting case of rapid depressurization

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

from isolated Hot Shutdown (reactor scram and main steam isolation valve closure, with initial pool temperature of 95°F) with assumed loss of one residual heat removal loop (Reference 2) was addressed as part of the analyses of Reference 3. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during plant testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

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

a. Average temperature ≤ 95°F with THERMAL POWER > 1% RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature ≤ 105°F with THERMAL POWER > 1% RTP and testing that adds heat to the suppression pool is being performed. This required value ensures that the plant has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 95°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 95°F is short enough not to cause a significant increase in plant risk.

c. Average temperature ≤ 110°F with THERMAL POWER ≤ 1% RTP. This requirement ensures that the plant will be shut down at > 110°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

Indication of 1% RTP varies with plant conditions and can be determined by more than one method. When at or near normal operating temperature, Reactor Coolant System (RCS) losses such as the Reactor Water Cleanup System, steam line drains and insulation inefficiency are approximately 1% RTP or

(continued)

BASES

LCO (continued)

less and reactor power level can be observed on the intermediate range monitor (IRM) Instrumentation. At this condition 25/40 divisions of full scale on IRM Range 7 is a convenient measure of reactor power essentially equivalent to 1% RTP. At 1% RTP, heat input is approximately equal to normal system heat losses. When RCS temperature is significantly below the normal operating temperature, maintaining reactor power level at or below the "point of adding heat" maintains power level well below 1% RTP.

APPLICABILITY

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

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power indication, the initial conditions exceed the conditions assumed for the References 1, 2, and 3 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above those assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool average temperature to be restored below the limit. Additionally, when suppression pool temperature is > 95°F, increased monitoring of the suppression pool temperature is required to ensure that it remains ≤ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly except when testing that adds heat to the suppression pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO

(continued)

BASES

ACTIONS

B.1 (continued)

does not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 1% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce power from full power conditions in an orderly manner and without challenging plant systems.

C.1

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

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

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

E.1 and E.2

If suppression pool average temperature cannot be maintained at ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours, and

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

the plant must be brought to at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The LCO 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," Bases contains a description of the suppression pool temperature monitoring system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequency is further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. UFSAR, Section 14.6.1.3.3.

2. NEDC-24361-P, James A. FitzPatrick Nuclear Power Plant Suppression Pool Temperature Response, August 1981.

3. GE-NE-T23-00737-01, James A. FitzPatrick Nuclear Power Plant Higher RHR Service Water Temperature Analysis, August 1996.

(continued)

BASES

REFERENCES (continued)

4. Letter from R. W. Reid (NRC) to G. T. Berry (NYPA), Request for Additional Information Regarding Suppression Pool Temperature Transients, December 9, 1977.

5. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a Design Basis Accident (DBA). The suppression pool must quench all the steam released through the Mark I Vent System downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment, which ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from the steam exhaust lines in the turbine driven systems (i.e., High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) System) and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between approximately 105,900 ft^3 at the low water level limit of 13.88 ft and 111,360 ft^3 at the high water level limit of 14.25 ft.

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

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS

Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent system downcomer clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of References 1, 2, and 4 remain valid.

Suppression pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

LCO

A limit that suppression pool water level be ≥ 13.88 ft and ≤ 14.25 ft is required to ensure that the primary containment conditions assumed for the safety analyses are met. Either the high or low water level limits were used in the safety analyses, depending upon which is more conservative for a particular calculation.

The LCO is modified by a note which states that the LCO is not required to be met up to four hours during Surveillances that cause suppression pool water level to be outside of limits. These Surveillances include required OPERABILITY testing of the High Pressure Coolant Injection System, the Reactor Core Isolation Cooling System, the suppression chamber-to-drywell vacuum breakers, the Core Spray System and the Residual Heat Removal System. The 4 hour allowance is adequate to perform the Surveillances and to restore the suppression pool water level to within limits.

APPLICABILITY

In MODES 1, 2, and 3, a DBA would cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. The requirement for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control."

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analyses are not met. If water level is below the minimum level, the pressure suppression function still exists as long as the vent system downcomer lines are covered, HPCI and RCIC

(continued)

BASES

ACTIONS

A.1 (continued)

turbine exhausts are covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis and the capability of the Residual Heat Removal Containment Spray System.

Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within limits. Also, it takes into account the low probability of an event requiring the suppression pool water level to be within limits occurring during this interval.

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.2.2.1

Verification of the suppression pool water level is to ensure that the required limits are satisfied. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.6.1.3.3.
2. GE-NE-T23-00737-01, James A. FitzPatrick Nuclear Power Plant Higher RHR Service Water Temperature Analysis, August 1996.
3. 10 CFR 50.36(c)(2)(ii).
4. 005N1724, “James A. FitzPatrick Nuclear Power Plant Short-Term Containment Analysis for Zero Drywell-to-Wetwell Pressure Differential,” Rev. 0, May 2019.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

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

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

The heat removal capability of one RHR pump is sufficient to meet the overall DBA pool cooling requirement for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or stuck open safety/relief valve (S/RV). S/RV leakage, High Pressure Coolant Injection System and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events. The RHR Suppression Pool Cooling System also ensures adequate net positive suction head (NPSH) is available for the Emergency Core Cooling System pumps.

APPLICABLE SAFETY ANALYSES

References 1 and 2 contain the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. References 2 and 3 contain the results of analyses used to predict local and bulk suppression pool temperatures following certain events including small break LOCAs and a stuck open S/RV. The analyses indicates that the heat removal capacity of the RHR

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

The RHR Suppression Pool Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

Following a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below design limits (Ref. 3). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE with power from two safety related redundant power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active component failure. An RHR suppression pool cooling subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

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

ACTIONS

A.1

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

(continued)

BASES

ACTIONS (continued)

B.1

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

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.3.2

Verifying that each required RHR pump develops a flow rate ≥ 7700 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME Code, Section XI (Ref. 5). This test confirms one point on the pump performance curve, and the results are indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. UFSAR, Section 14.6.1.3.3.
2. GE-NE-T23-00737-01, James A. FitzPatrick Nuclear Power Plant Higher RHR Service Water Temperature Analysis, August 1996.
3. NEDC-24361-P, James. A FitzPatrick Nuclear Power Plant Suppression Pool Temperature Response, August 1981.
4. 10 CFR 50.36(c)(2)(ii).
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Deleted

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Oxygen Concentration

BASES

BACKGROUND	The primary containment is designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis of reactor coolant. The primary method to control hydrogen is to inert the primary containment with nitrogen gas. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen < 4.0 v/o works together with the Containment Atmosphere Dilution (CAD) System to mitigate events that produce hydrogen and oxygen. For example, an event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment., but oxygen concentration will remain < 4.0 v/o and no combustion can occur. Long term generation of both hydrogen and oxygen from radiolytic decomposition of water is controlled by the CAD System. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.
APPLICABLE SAFETY ANALYSIS	The Reference 1 calculations assume that the primary containment is inerted when a Design Basis loss of coolant accident (LOCA) occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment. Oxygen, which is subsequently generated by radiolytic decomposition of water, is controlled by the CAD System. Primary containment oxygen concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).
LCO	The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that an event that produces any amount of hydrogen does not result in a combustible mixture inside primary containment.

(continued)

BASES (continued)

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted. The primary containment must be inert in MODE 1 and 2, since this is the condition with the highest probability of an event that could produce hydrogen.

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o while operating in MODE 1 or 2, oxygen concentration must be restored to < 4.0 v/o within 72 hours. The 72 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable because inerting the primary containment prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup, after entering Modes 1 and 2, and de-inerted as soon as possible in the plant shutdown. It is acceptable to intentionally enter the Required Action A.1 prior to a shutdown in order to begin de-inerting the primary containment prior to exiting the Applicability.

B.1

If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, power must be reduced to MODE 3 within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

The primary containment must be determined to be inert by verifying that oxygen concentration is < 4.0 v/o. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 5.2.3.8.
2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Containment Atmosphere Dilution (CAD) System

BASES

BACKGROUND

The CAD System functions to maintain combustible gas concentrations within the primary containment at or below the flammability limits following a postulated loss of coolant accident (LOCA) by diluting hydrogen and oxygen with nitrogen. To ensure that a combustible gas mixture does not occur, oxygen concentration is kept < 4.0 volume percent (v/o).

The CAD System is manually initiated and consists of two independent, 100% capacity subsystems. Each subsystem includes a liquid nitrogen supply tank, ambient vaporizer, electric heater, and connected piping to supply the drywell and suppression chamber volumes. The CAD subsystems are utilized for normal makeup. The CAD subsystems also provide the pneumatic supply requirements of instruments and controls inside the drywell including the long term (100 days) pneumatic supply requirements of the Automatic Depressurization System (ADS) valves and accumulators following a LOCA. In addition, separate lines from each liquid nitrogen storage tank with separate ambient heat exchangers and pressure control valves provides the pneumatic supply for the CAD subsystem pneumatically operated valves. The nitrogen storage tanks each contain ≥ 1400 gal, which is adequate for 3 days of CAD subsystem operation. This provides sufficient time to replenish the tanks for the long term supply requirements.

The CAD System operates in conjunction with emergency operating procedures that are used to reduce primary containment pressure periodically during CAD System operation. This combination results in a feed and bleed approach to maintaining hydrogen and oxygen concentrations below combustible levels.

APPLICABLE SAFETY ANALYSES

To evaluate the potential for hydrogen and oxygen accumulation in primary containment following a LOCA, hydrogen and oxygen generation is calculated (as a function of time following the initiation of the accident). The assumptions stated in Reference 1 are used to maximize the amount of hydrogen and oxygen generated. The calculation confirms that when the mitigating systems are actuated in accordance with emergency operating procedures, the peak oxygen concentration in primary containment is < 4.0 v/o (Ref. 2).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Hydrogen and oxygen may accumulate within primary containment following a LOCA as a result of:

a. A metal water reaction between the zirconium fuel rod cladding and the reactor coolant; or

b. Radiolytic decomposition of water in the Reactor Coolant System.

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

LCO

Two CAD subsystems must be OPERABLE. This ensures operation of at least one CAD subsystem in the event of a worst case single active component failure. Operation of at least one CAD subsystem is designed to maintain primary containment post-LOCA oxygen concentration < 4.0 v/o for 3 days.

APPLICABILITY

In MODES 1 and 2, the CAD System is required to maintain the oxygen concentration within primary containment below the flammability limit of 5.0 v/o following a LOCA. This ensures that the relative leak tightness of primary containment is adequate and prevents damage to safety related equipment and instruments located within primary containment.

In MODE 3, both the hydrogen and oxygen production rates and the total amounts produced after a LOCA would be less than those calculated for the Design Basis LOCA. Thus, if the analysis were to be performed starting with a LOCA in MODE 3, the time to reach a flammable concentration would be extended beyond the time conservatively calculated for MODES 1 and 2. The extended time would allow hydrogen removal from the primary containment atmosphere by other means and also allow repair of an inoperable CAD subsystem, if CAD were not available. Therefore, the CAD System is not required to be OPERABLE in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations of these MODES. Therefore, the CAD System is not required to be OPERABLE in MODES 4 and 5.

(continued)

BASES (continued)

ACTIONS

A.1

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

B.1 and B.2

With two CAD subsystems inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the Primary Containment Inerting System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two CAD subsystems

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

inoperable for up to 7 days. Seven days is a reasonable time to allow two CAD subsystems to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

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

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

Verifying that there is ≥ 1400 gal of liquid nitrogen supply in each CAD subsystem will ensure at least 3 days of post-LOCA CAD operation. This minimum volume of liquid nitrogen allows sufficient time after an accident to replenish the nitrogen supply for long term inerting. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.3.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in each of the CAD subsystem flow paths provides assurance that the proper flow paths exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.2 (continued)

A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable because the CAD System is manually initiated. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Safety Guide 7, March 10, 1971.

2. UFSAR, Section 5.2.3.8.3.

3. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

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

The secondary containment is a structure that surrounds the primary containment and is designed to provide secondary containment for postulated loss-of-coolant accidents inside the primary containment. The Secondary Containment also surrounds the refueling facilities and is designed to provide primary containment for the postulated refueling accident. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump and motor heat load additions). To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABLE SAFETY ANALYSIS

There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a loss of coolant accident (LOCA) (Ref. 1) and a refueling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours) inside secondary containment (Ref. 2). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that fission products entrapped within the secondary containment structure will be treated by the SGT System prior to discharge to the environment.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)	Secondary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).
LCO	An OPERABLE secondary containment provides a control volume into which fission products that leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, or are released directly to the secondary containment as a result of a refueling accident, can be processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.
APLLICABILITY	In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY. In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during movement of recently irradiated fuel assemblies in the secondary containment. Due to radioactive decay, secondary containment is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).
ACTIONS	A.1 If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

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

C.1

Movement of recently irradiated fuel assemblies in the secondary containment can be postulated to cause significant fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. Therefore, movement of recently irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of this activity shall not preclude completing an action that involves moving a component to a safe position.

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

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. Momentary transients on the installed instrumentation due to gusty wind conditions are considered acceptable and not cause for failure of this SR. The SR is modified by a Note which states the SR is not required to be met for up to 4 hours if an analysis demonstrates that one SGT subsystem remains capable of establishing the required secondary containment vacuum. Use of the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1 (continued)

Note is expected to be infrequent but may be necessitated by situations in which secondary containment vacuum may be less than the required containment vacuum, such as, but not limited to, wind gusts or failure or change of operating normal ventilation subsystems. These conditions do not indicate any change in the leak tightness of the secondary containment boundary. The analysis should consider the actual conditions (equipment configuration, temperature, atmospheric pressure, wind conditions, measured secondary containment vacuum, etc.) to determine whether, if an accident requiring secondary containment to be OPERABLE were to occur, one train of SGT could establish the assumed secondary containment vacuum within the time assumed in the accident analysis. If so, the SR may be considered met for a period up to 4 hours. The 4 hour limit is based on the expected short duration of the situation when the Note would be applied. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur and provides adequate assurance that exfiltration from the secondary containment will not occur. SR 3.6.4.1.2 also requires equipment hatches to be sealed. In this application, the term "sealed" has no connotation of leak tightness.

An access opening contains at least one inner and one outer door. The intent is to not breach the secondary containment, which is achieved by maintaining the inner or outer portion of the barrier closed. SR 3.6.4.1.3 provides an exception to allow brief, unintentional, simultaneous opening of both an inner and outer secondary containment access door for entry and exit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.1.4

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 verifies that a pressure in the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 (continued)

secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can be maintained. When the SGT System is operating as designed, the maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.4 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 6000 cfm under calm wind conditions. Calm wind conditions will result in little, if any, infiltration to the secondary containment. Therefore, if the test is performed at other wind conditions and the results are acceptable, this test may be considered met. This test method is acceptable since extreme wind conditions are only expected to be present for a few hours a year. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The primary purpose of this SR is to ensure secondary containment boundary integrity. The secondary purpose of this SR is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements which serves the primary purpose of ensuring OPERABILITY of the SGT System. The inoperability of the SGT subsystem does not necessarily constitute a failure of this Surveillance relative to the secondary containment OPERABILITY. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.6.1.3.
2. UFSAR, Section 14.6.1.4.
3. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Refs. 1 and 2). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, or that are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices.

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

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

APPLICABLE SAFETY ANALYSIS

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1) and a refueling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours) inside secondary containment (Ref. 2). The secondary containment performs no active function in response to either of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)	environment. Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment. SCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).
LCO	SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs. The power operated automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 4. The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 4.
APLLICABILITY	In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required. In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for situations under which significant radioactive releases can be postulated, such as during movement of recently irradiated fuel assemblies in the secondary containment. Moving recently irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2. And 3. Due to radioactive decay, SCIVs are only required to be OPERABLE during fuel handling involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

(continued)

BASES (continued)

ACTIONS

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

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

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

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration, and the probability of a DBA, which requires the SCIVs to close, occurring during this short time is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the valves are operated under administrative controls and the probability of their

(continued)

BASES

APPLICABLE SAFETY ANALYSIS

A.1 and A.2 (continued)

misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

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

B.1

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

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if only one SCIV is inoperable in multiple penetrations.

C.1 and C.2

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

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

D.1

If any Required Action and associated Completion Time are not met, the plant must be placed in a condition in which the LCO does not apply. If applicable, the movement of recently irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of this activity shall not preclude completion of movement of a component to a safe position.

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

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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

BASES

APPLICABLE SAFETY ANALYSIS (continued)

SR 3.6.4.2.1 (continued)

position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

SR 3.6.4.2.2

Verifying that the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.6.1.3.
2. UFSAR, Section 14.6.1.4.
3. 10 CFR 50.36(c)(2)(ii).
4. Technical Requirements Manual.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by UFSAR, Section 16.6 (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The SGT System consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter assembly, centrifugal fan and controls. The SGT subsystems share a common inlet line. The inlet line is connected through separate valved connections to the reactor building above the refuel floor, reactor building below refuel floor, primary containment drywell and suppression chamber, HPCI turbine gland seal exhauster, main steam leak collection system and Auxiliary Gas Treatment System. Both 100% capacity SGT subsystem fans exhaust to the elevated release point (the main stack), through a common exhaust duct. The SGT subsystem fans are designed to automatically start upon a secondary containment isolation signal.

The fan suctions are cross connected by a single line and two normally opened manual cross tie valves to accommodate decay heat removal. Air for decay heat removal enters the idle SGT subsystem from the SGT room via a motor operated valve and restricting orifice. The air is drawn through the filter, removing the decay heat from the idle subsystem filters, passes through the cross tie line to the opposite operating SGT subsystem fan, and is exhausted to the main stack.

Each SGT filter assembly consists of (components listed in order of the direction of the air flow):

a. A demister;

b. An electric heater;

c. A prefilter;

d. A high efficiency particulate air (HEPA) filter;

e. A charcoal adsorber; and

f. A second HEPA filter.

(continued)

BASES

BACKGROUND (continued)

The SGT System equipment and components are sized to reduce and maintain the secondary containment at a negative pressure of 0.25 inches water gauge when the system is in operation under neutral wind conditions and the SGT fans exhausting at a rate of 6,000 cfm.

The demister is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream to less than 70% (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

The SGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both SGT subsystem fans start. Upon verification that both subsystems are operating, one subsystem is normally shut down.

APPLICABLE SAFETY ANALYSIS

The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident and refueling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours) (Ref. 3). For all events analyzed, the SGT System is shown to be automatically initiated to reduce. via filtration and adsorption, the radioactive material released to the environment.

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

LCO

Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two OPERABLE subsystems ensures operation of at least one SGT subsystem in the event of a single active failure. An OPERABLE SGT subsystem consists of a demister, heater, prefilter, HEPA filter, charcoal adsorber, a final HEPA filter, centrifugal fan, and associated ductwork, dampers, valves and controls.

(continued)

BASES (continued)

APLLICABILITY

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

In MODES 4 and 5. the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore. maintaining the SGT System in OPERABLE status is not required in MODE 4 or 5. except for other situations under which significant releases of radioactive material can be postulated. such as during movement of recently irradiated fuel assemblies in the secondary containment. Due to radioactive decay. the SGT system is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

ACTIONS

A.1

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

B.1 and B.2

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

C.1 and C.2

During movement of recently irradiated fuel assemblies, in the secondary containment, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem should immediately be placed in operation. This action

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing a significant amount of radioactive material to the secondary containment, thus placing the plant in a condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies must immediately be suspended. Suspension of this activity must not preclude completion of movement of a component to a safe position.

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

D.1

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

E.1

When two SGT subsystems are inoperable, if applicable, movement of recently irradiated fuel assemblies in secondary containment must immediately be suspended. Suspension of this activity shall not preclude completion of movement of a component to a safe position.

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

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem fan for ≥ 15 continuous minutes ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR verifies that each SGT subsystem starts on receipt of an actual or simulated initiation signal. In addition, the OPERABILITY of each SGT decay heat cooling valve is verified to ensure the valve closes on subsystem initiation (interlocked with the suction valve) and opens when shutdown. This will ensure the mitigation function as well as the decay heat cooling mode of each SGT subsystem is available. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.3.4

This SR verifies that the filter cooling cross-tie valves are OPERABLE. This ensures that the decay heat cooling mode of SGT System operation is available. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 5.3.3.4.
3. UFSAR, Section 14.6.
4. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System

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, two 4000 gpm pumps, a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity with two pumps operating to maintain safe shutdown conditions. 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 UFSAR, Section 9.7.3, Reference 1.

Cooling water is pumped by the RHRSW pumps from the intake structure through the tube side of the RHR heat exchangers, and discharges to the discharge structure via the Service Water System.

The system is initiated manually from the control room. If operating during a loss of coolant accident (LOCA), the system is automatically tripped to allow the diesel generators to automatically power only that equipment necessary to reflood the core. The system is assumed in the analysis to be manually started 10 minutes after the LOCA.

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool via the RHR System 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 UFSAR, Sections 4.8, 5.1 and Chapter 14 (Refs. 2, 3 and 4, respectively). These analyses explicitly assume that the RHRSW System will

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BASES

APPLICABLE SAFETY ANALYSES (continued)

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 combinations of RHR System failures. The worst case single active failure that would affect the performance of the RHRSW System is any failure that would disable one subsystem of the RHRSW System. As discussed in the UFSAR, Section 14.6.1.3.3 (Ref. 5) for these analyses, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur 10 minutes after a DBA. The RHRSW flow assumed in the analyses is 4000 gpm per pump with two pumps operating in one loop. In this case, the maximum suppression chamber water temperature is 213°F which is below the design temperature of 220°F.

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

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. Two pumps are OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the intake structure and transferring the water to the RHR heat exchangers at the assumed flow rate and discharging the water to the discharge structure.

The requirements of the ultimate heat sink are not addressed in this LCO since the requirements of the ultimate heat sink are addressed by the emergency service water pump requirements (LCO 3.7.2, "Emergency Service Water (ESW) System and Ultimate Heat Sink (UHS)").

APPLICABILITY

In MODES 1, 2, and 3, the RHRSW System is 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 3.6.1.9,

(continued)

BASES

APPLICABILITY (continued)

"Residual Heat Removal (RHR) Containment Spray") and decay heat removal (LCO 3.4.7, "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 systems it supports and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the RHR Shutdown Cooling System (LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System – Cold Shutdown," LCO 3.9.7, "Residual Heat Removal (RHR) – High Water Level," and LCO 3.9.8, "Residual Heat Removal (RHR) – Low Water Level"), which require portions of the RHRSW System to be OPERABLE, will govern RHRSW System operation in MODES 4 and 5.

ACTIONS

A.1

With one RHRSW pump inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. With the plant in this condition, the remaining OPERABLE RHRSW pumps are adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced RHRSW capability. The 30 day Completion Time is based on the remaining RHRSW heat removal capability, and the low probability of a DBA with concurrent worst case single failure.

B.1

With one RHRSW pump inoperable in each subsystem, if no additional failures occur in the RHRSW System, then the remaining OPERABLE pumps 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. Therefore, continued operation is permitted only for a limited time. One inoperable pump is required to be restored to OPERABLE status within 7 days. The 7 day Completion Time for restoring one inoperable RHRSW pump to

(continued)

BASES

ACTIONS

B.1 (continued)

OPERABLE status is based on engineering judgment, considering the level of redundancy provided and low probability of an event occurring requiring RHRSW during this time period.

C.1

Required Action C.1 is intended to handle the inoperability of one RHRSW subsystem for reasons other than Condition A (e.g., inoperable flow path, or both pumps inoperable). The Completion Time of 7 days is allowed to restore the RHRSW subsystem to OPERABLE status. With the plant in this condition, the remaining OPERABLE 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 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.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.4.7, be entered and Required Actions taken if an inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

D.1

With both RHRSW subsystems inoperable for reasons other than Condition B (e.g., both subsystems with inoperable flow paths, or one subsystem with an inoperable pump and one subsystem with an inoperable flow path), the RHRSW System is not capable of performing its intended function. At least one subsystem must be restored to OPERABLE status within 8 hours. The 8 hour Completion Time for restoring one RHRSW subsystem to OPERABLE status, is based on the Completion Times provided for the RHR suppression pool cooling and spray functions.

(continued)

BASES

ACTIONS

D.1 (continued)

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.4.7, be entered and Required Actions taken if an inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

E.1 and E.2

If any Required Action and associated Completion Time is not met, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 9.7.3.
2. UFSAR, Section 4.8.
3. UFSAR, Section 5.1.
4. UFSAR, Chapter 14.
5. UFSAR, Section 14.6.1.3.3.
6. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.2 Emergency Service Water (ESW) System and Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The ESW System is designed to provide cooling water for the removal of heat from equipment, such as the emergency diesel generators (EDGs), electric bay coolers, crescent area coolers, cable tunnel/switchgear room coolers and control room and relay room air handling units, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. Upon receipt of a loss of offsite power or loss of coolant accident (LOCA) signal, the EDGs will start which in turn starts the associated ESW pump. Each ESW pump will automatically pump to the associated EDG cooler. The remaining ESW loads will be automatically cooled when the associated ESW supply header isolation valve opens and the associated ESW minimum flow valve closes. This occurs when the ESW lockout matrix logic actuates upon low reactor building closed loop cooling water pump discharge pressure. This logic is discussed in LCO 3.3.7.3, "Emergency Service Water (ESW) System Instrumentation". In addition, the ESW pumps will automatically start in response to the ESW lockout matrix logic. However, this function is not required for safe reactor shutdown since the ESW pumps will start when any associated EDG starts.

The ESW System consists of the UHS and two independent and redundant subsystems. Each of the two ESW subsystems is made up of a header, one 3700 gpm pump, a suction source, valves, piping and associated instrumentation. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other system. The ESW System is described in UFSAR, Section 9.7.1 (Ref. 1).

Cooling water flows from Lake Ontario (UHS) through the intake tunnel to the screenwell where the water is pumped by the ESW pumps to components through the two main headers. After removing heat from the components, the water is discharged to the discharge tunnel where it returns to Lake Ontario.

The lake intake structure is a reinforced concrete structure sitting on the lake bottom at a distance of approximately 900 ft from the shoreline in approximately 25 ft of water. The top surface of the intake structure is at the 233 ft elevation (above sea level), which is approximately 10 ft below the historically lowest monthly mean lake

(continued)

BASES

BACKGROUND (continued)

level. The intake is a roofed structure which draws water in through eight side openings. Six of the openings are protected with bar racks spaced at 1 ft centers to block the entrance of large debris. This results in water being taken in at lower levels and prevents the formation of vortices at the surface, thus minimizing the possibility of floating ice being drawn down from the surface. The side intake area is approximately 620 ft^2. During normal operation, with a maximum nominal operating flow of 435,000 gpm from three circulating water pumps and two normal service water pumps, the average intake velocity is approximately 1.6 ft per second across the intake bar racks. However, during safe shutdown conditions with only two Residual Heat Removal Service Water (RHRSW) pumps and one ESW pump in operation, the maximum nominal flow is reduced to 10,000 gpm, corresponding to an average intake velocity of 0.04 ft per second.

APPLICABLE SAFETY ANALYSIS

Since Lake Ontario is the UHS, sufficient water inventory is available for all ESW System post LOCA cooling requirements for a 30 day period. The OPERABILITY of the ESW System is assumed in evaluations of the equipment required for safe reactor shutdown presented in the UFSAR, Chapters 5 and 14 (Refs. 2 and 3, respectively). These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The ability of the ESW System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in References 2 and 3. The ability to provide onsite emergency AC power is dependent on the ability of the ESW System to cool the EDGs. The long term cooling capability of RHR and core spray pumps is dependent on the capability of the ESW System to provide cooling to the EDGs as well as the crescent area coolers.

The ESW System, together with the UHS, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

The ESW subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of ESW is required to provide the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of ESW must be OPERABLE. At least one subsystem will

(continued)

BASES

APPLLICABLE SAFETY ANALYSES (continued)

operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has an OPERABLE UHS, one OPERABLE pump, and an OPERABLE flow path capable of taking suction from the intake structure and transferring the water to the appropriate equipment. OPERABILITY of equipment cooled by the ESW System is based on heat transfer, not flow rates; OPERABILITY of the ESW pumps is based on measured performance remaining within allowable IST Program acceptance criteria.

The OPERABILITY of the UHS is based on having a minimum water level in the screenwell of 236.5 ft mean sea level and a maximum water temperature of 85°F.

The isolation of the ESW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the ESW System.

APPLICABILITY

In MODES 1, 2, and 3, the ESW System and UHS are required to be OPERABLE to support OPERABILITY of the equipment serviced by the ESW System. Therefore, the ESW System and UHS are required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the ESW System and UHS are determined by the systems they support and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, LCO 3.7.4, "Control Room AC System," and LCO 3.8.2, "AC Sources - Shutdown," which require the ESW System to be OPERABLE, will govern ESW System operation in MODES 4 and 5.

ACTIONS

A.1

With one ESW subsystem inoperable, the ESW subsystem must be restored to OPERABLE status within 7 days. With the plant in this condition, the remaining OPERABLE ESW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single active component failure in the OPERABLE ESW subsystem could result in loss of ESW function.

The 7 day Completion Time is based on the redundant ESW System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occurring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable EDG subsystem.

(continued)

BASES

ACTIONS

A.1 (continued)

Required Action A.1 is modified by a Note indicating that the applicable Conditions of LCO 3.8.1, "AC Sources - Operating," be entered and Required Actions taken if the inoperable ESW subsystem results in an inoperable EDG subsystem. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for this component.

B.1 and B.2

If the ESW subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both ESW subsystems are inoperable, or the UHS is determined inoperable the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies the water level in the screenwell to be sufficient for the proper operation of the ESW and RHRSW pumps (net positive suction head and pump vortexing are considered in determining this limit). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.2.2

Verification of the UHS temperature ensures that the heat removal capability of the ESW System is within the assumptions of the DBA analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.2.3

Verifying the correct alignment for each manual, power operated, and automatic valve in each ESW subsystem flow path provides assurance that the proper flow paths will exist for ESW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.3 (continued)

the nonaccident position, and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

This SR is modified by a Note indicating that isolation of the ESW System to components or systems may render those components or systems inoperable, but does not necessarily affect the OPERABILITY of the ESW System. As such, when all ESW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the ESW System may still be considered OPERABLE.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.2.4

This SR verifies the automatic start capability of the ESW pump in each subsystem. This is demonstrated by the use of an actual or simulated initiation signal associated with each EDG. In addition, the proper positioning of the ESW supply header isolation valves and the ESW minimum flow valves, upon actual or simulated ESW lockout matrix logic actuation, must be demonstrated in this SR. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.7.3 overlaps this Surveillance to provide complete testing of the assumed safety function. ESW will not be supplied to the Reactor Building Closed Loop Cooling System during the performance of this test to avoid contaminating this system with lake water.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.7.1.
2. UFSAR, Chapter 5.
3. UFSAR, Chapter 14.
4. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.3 Control Room Emergency Ventilation Air Supply (CREVAS) System

BASES

BACKGROUND

The CREVAS System; a portion of the Control Room Air Conditioning (AC) System provides a protected environment from which occupants can control the plant following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The safety related function of the CREVAS System includes two redundant high efficiency air filtration subsystems for emergency treatment of outside supply air and a Control room Envelope (CRE) boundary that limits the inleakage of unfiltered air. Each CREVAS subsystem consists of a prefilter, a high efficiency particulate air (HEPA) filter, two activated charcoal adsorber sections in series, a second HEPA filter, a control room emergency air supply fan, an air handling unit (excluding the condensing unit), a recirculation exhaust fan and the associated ductwork, valves or dampers, doors, barriers and instrumentation. Prefilters and HEPA filters remove particulate matter, which may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the plant during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

The CREVAS System is a standby system, parts of which also operate during normal plant operations to maintain the CRE environment. Upon occurrence of a DBA or receipt of an alarm from a radiation monitor installed in the control room ventilation intake duct (indicative of conditions that could result in radiation exposure to CRE

(continued)

BASES (continued)

BACKGROUND

occupants), the CREVAS System is manually placed in the isolate mode of operation to minimize infiltration of contaminated air into the CRE. A system of dampers isolates the CRE. Outside air is taken in at either the primary or secondary ventilation intake and is passed through one of the charcoal adsorber filter subsystems for removal of airborne radioactive particles. This filtered air is then mixed with recirculated air from one of the recirculation exhaust fans and then passed through one of two fans of the air handling units where it can be cooled before it is recirculated back to the control room. The cooling capability of the air handling units is not required to satisfy the requirements of this Specification.

The CREVAS System is designed to maintain a habitable environment in the CRE for a 31 day continuous occupancy after a DBA without exceeding 5 rem whole body dose or its equivalent to any part of the body. A single CREVAS subsystem will pressurize the CRE to ≥ 0.125 inches water gauge relative to external areas adjacent to the CRE boundary to minimize infiltration of air from all surrounding areas adjacent to the CRE boundary. CREVAS System operation in maintaining CRE habitability is discussed in the UFSAR, Sections 9.9.3.11 and 14.8.2, (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSIS

The ability of the CREVAS System to maintain the habitability of the CRE is an explicit assumption for the safety analyses presented in the UFSAR, Chapters 6 and 14 (Refs. 3 and 4, respectively). The isolate mode of the CREVAS System is assumed to operate following a DBA as discussed in the UFSAR, Section 14.8.2 (Ref. 2). The radiological doses to control room personnel as a result of the various DBAs are summarized in Reference 2.

The CREVAS System provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 6). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 7).

The CREVAS System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

(continued)

BASES (continued)

LCO

Two redundant subsystems of the CREVAS System are required to be OPERABLE to ensure that at least one is available, if a single active failure disables the other subsystem. Total CREVAS system failure, such as from a loss of both ventilation subsystems or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem whole body or its equivalent to any part of the body to the CRE occupants in the event of some DBAs.

Each CREVAS subsystem is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A subsystem is considered OPERABLE when its associated:

a. Fans are OPERABLE (i.e., one control room emergency air supply fan, one air handling unit fan, one recirculation exhaust fan);

b. A prefilter, two HEPA filters and charcoal adsorbers are not excessively restricting flow and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In order for the CREVAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the CREVAS System must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA, since the DBA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced because of the pressure and temperature limitations in these MODES. Therefore, maintaining the CREVAS System OPERABLE is not required in MODE 4 or 5, except during movement of recently irradiated fuel assemblies in the secondary containment. Due to radioactive decay, the CREVAS system is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor within the previous 96 hours).

ACTIONS

A.1

With one CREVAS subsystem inoperable for reasons other than an inoperable CRE boundary, the inoperable CREVAS subsystem must be restored to OPERABLE status within 7 days. With the plant in this condition, the remaining OPERABLE CREVAS subsystem is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE subsystem could result in loss of the CREVAS System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

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

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem whole body or its equivalent to any part of the body), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not

(continued)

BASES

ACTIONS

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

exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected form hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor ad maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

C.1 and C.2

In MODE 1, 2, or 3, if the inoperable CREVAS subsystem or CRE boundary cannot be restored to OPERABLE status within the required Completion Time, the plant must be placed in a MODE that minimizes accident risk. To achieve this status, the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1, and D.2

LCO 3.0.3 is not applicable when in MODE 4 or 5. However, since recently irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply.

If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment, if the inoperable CREVAS subsystem cannot

(continued)

BASES

ACTIONS

D.1, and D.2 (continued)

be restored to OPERABLE status within the required Completion Time, the OPERABLE CREVAS subsystem may be placed in the isolate mode. This action ensures that the remaining subsystem is OPERABLE, and that any active failure will be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the CRE. This places the plant in a condition that minimizes the accident risk.

If applicable, movement of recently irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of this activity shall not preclude completion of movement of a component to a safe position.

E.1

If both CREVAS subsystems are inoperable in MODE 1, 2, or 3 for reasons other than an inoperable CRE boundary (i.e., Condition B), the CREVAS System may not be capable of performing the intended function and the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

F.1

LCO 3.0.3 is not applicable when in MODE 4 or 5. However, since recently irradiated fuel assembly movement can occur in MODES 1, 2, or 3, the Required Actions of Condition F are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment, with two CREVAS subsystems inoperable or with one or more CREVAS subsystems inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the plant in a condition that minimizes the accident risk.

If applicable, movement of recently irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of this activity shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that a subsystem in a standby mode starts on demand and continues to operate. These subsystems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing each subsystem once every three months provides an adequate check on this system. Since the CREVAS System does not contain heaters, it need only be operated for ≥ 15 minutes to demonstrate the function of the system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.3.2

This SR verifies that the required CREVAS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.3.3

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem whole body or its equivalent to any part of the body and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3,(Ref. 8) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 9). These compensatory measures may also be used as

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.3 (continued)

mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 10). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

REFERENCES

1. UFSAR, Section 9.9.3.11.
2. UFSAR, Section 14.8.2.
3. UFSAR, Chapter 6.
4. UFSAR, Chapter 14.
5. 10 CFR 50.36(c)(2)(ii).
6. Calculation No. JAF-CALC-CRC-01953, “Toxic Chemical Control Room Habitability Analysis”, Revision 1, dated April 7, 2004.
7. Interface Control Document No. JAF-ICD-04-00038, “Control Room Habitability Smoke Evaluation”, Revision 0, dated March 2, 2004.
8. Regulatory Guide 1.196, “Control Room Habitability at Light Water Nuclear Power Reactors”, dated January 2007
9. NEI 99-03, “Control Room Habitability Assessment”, Revision 1, dated March, 2003.
10. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI), “NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the context of Control Room Habitability.” (ADAMS Accession No ML040300694), dated January 30, 2004.

B 3.7 PLANT SYSTEMS

B 3.7.4 Control Room Air Conditioning (AC) System

BASES

BACKGROUND

The Control Room AC System provides temperature control for the control room while the Control Room Emergency Ventilation Air Supply (CREVAS) System (a mode of the Control Room AC) provides a radiologically controlled environment (refer to the Bases of for LCO 3.7.3, "Control Room Emergency Ventilation Air Supply (CREVAS) System").

The Control Room AC System consists of two redundant subsystems that provide cooling of recirculated control room air. Each subsystem consists of cooling coils, fans, chillers, compressors, ductwork, dampers, and instrumentation and controls to provide for control room temperature control. A heater is located in the ductwork associated with each control room area.

The Control Room AC System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem provides the required temperature control to maintain a suitable control room environment for a sustained occupancy of 20 persons. The design conditions for the control room environment are 75°F and 50% relative humidity. This can be accomplished when a control room chiller is providing the cooling medium to the cooling coils of an air handling unit. The control room chillers are non-safety related; however the Control Room AC System still meets safety-related QA Category I requirements when the Emergency Service Water System is aligned to directly supply the cooling coils. The resulting maximum control room environmental conditions when the Emergency Service Water System is supplying the air handling unit cooling coils is 104°F assuming a lake temperature of 85°F. This satisfies the OPERABILITY requirements of the control room equipment. The Control Room AC System operation in maintaining the control room temperature is discussed in the UFSAR, Section 9.9.3.11 (Ref. 1).

APPLICABLE SAFETY ANALYSIS

The design basis of the Control Room AC System is to maintain the control room temperature for a 31 day continuous occupancy.

The Control Room AC System components are arranged in redundant safety related subsystems. During emergency operation, the Control

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)	Room AC System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single active component failure of a component of the Control Room AC System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The Control Room AC System is designed in accordance with Seismic Category I requirements. The Control Room AC System is capable of removing sensible and latent heat loads from the control room, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY. The Control Room AC System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).
LCO	Two redundant subsystems of the Control Room AC System are required to be OPERABLE to ensure that at least one is available, assuming a single active component failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits. The Control Room AC System is considered OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both subsystems. These components include the air handling units, recirculation exhaust fans, air handling unit fans, ductwork, dampers, and associated instrumentation and controls. The cooling coils of the air handling units may be cooled by the control room chillers, but to satisfy this LCO the Emergency Service Water System must be capable of alignment to provide cooling water directly to the cooling coils.
APPLICABILITY	In MODE 1, 2, or 3, the Control Room AC System must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY limits following control room isolation. In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Control Room AC System OPERABLE is not required in MODE 4 or 5, except during movement of recently irradiated fuel assemblies in the secondary containment. Due to radioactive decay, the Control Room AC system is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

(continued)

BASES (continued)

ACTIONS

A.1

With one control room AC subsystem inoperable, the inoperable control room AC subsystem must be restored to OPERABLE status within 30 days. With the plant in this condition, the remaining OPERABLE control room AC subsystem is adequate to perform the control room air conditioning function. However, the overall reliability is reduced because a single active component failure in the OPERABLE subsystem could result in loss of the control room air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring control room isolation, the consideration that the remaining subsystem can provide the required protection, and the availability of alternate safety and nonsafety cooling methods.

B.1 and B.2

If both control room AC subsystems are inoperable, the Control Room AC System may not be capable of performing its intended function. Therefore, the control room area temperature is required to be monitored to ensure that temperature is being maintained low enough that equipment in the control room is not adversely affected. With the control room temperature being maintained within the temperature limit, 72 hours is allowed to restore a control room AC subsystem to OPERABLE status. This Completion Time is reasonable considering that the control room temperature is being maintained within limits and the low probability of an event occurring requiring control room isolation.

C.1 and C.2

In MODE 1, 2, or 3, if the inoperable control room AC subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE that minimizes risk. To achieve this status, the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1 and D.2

LCO 3.0.3 is not applicable while in MODE 4 and 5. However, since recently irradiated fuel assembly movement can occur in MODES 1, 2, or 3 the Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply.

BASES

ACTIONS

D.1 and D.2 (continued)

If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE control room AC subsystem may be placed immediately in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the plant in a condition that minimizes risk.

If applicable, movement of recently irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of this activity shall not preclude completion of movement of a component to a safe position.

E.1

LCO 3.0.3 is not applicable when in MODE 4 or 5. However, since recently irradiated fuel assembly movement can occur in MODE 1, 2, or 3 the Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply.

If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment, if Required Actions B.1 and B.2 cannot be met within the required Completion Times, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the plant in a condition that minimizes risk.

If applicable, handling of recently irradiated fuel in the secondary containment must be suspended immediately. Suspension of this activity shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the safety analyses with ESW providing water to the cooling coils of the air handling units. Heat transfer testing is not performed on the Control Room (CR) and Relay Room (RR) Air Handlin Units (AHUs) as these coolers are closed loop, glycol based systems which are not prone to fouling. To verify the system has the capability to remove the assumed heat, the ESW supply function (safety related) is required to be operable and the following surveillance requirements met: 1) the manual valves needed to initiate ESW flow to these coolers are cycled to verify operability; 2) the ESW supply piping to the AHUs is flushed during check valve testing; and 3) flow rates are measured against target flow rates. Therefore, any degradation would be detected and corrected through the corrective action program. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

JAF calculations verify maximum Allowable Tube Plugging Limit for CR and RR AHUs if maintenance is required on the AHUs. The level of allowed plugging provides a margin in the CR and RR equipment heat load and still maintains the CR and RR below 104° F under accident conditions using ESW at 85° F. In addition, JAF calculations state the potential for plugged tubes is low crediting use of a closed loop cooling water system using glycol/demineralized water (not service water) as the cooling medium.

REFERENCES

1. UFSAR, Section 9.9.3.11.
2. 10 CFR 50.36(c)(2)(ii).
3. SEP-SW-001 Rev.0, NRC Generic Letter 89-13 Service Water Program.

B 3.7 PLANT SYSTEMS

B 3.7.5 Main Condenser Steam Jet Air Ejector (SJAE) Offgas

BASES

BACKGROUND

During plant operation, steam from the low pressure turbine is exhausted directly into the main condenser. Air and noncondensible gases are collected in the main condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser (SJAE) Offgas System. The offgas from the main condenser normally includes radioactive gases.

The Main Condenser SJAE Offgas System has been incorporated into the plant design to reduce the gaseous radwaste emission and operates in three modes. During the startup mode, the SJAE offgas is directed to a 24 inch holdup pipe. During the intermediate mode the SJAE offgas is first directed to a recombiner and then to the same 24 inch holdup pipe. Finally in the normal mode of operation, the SJAE offgas is directed to the recombiner and then to charcoal beds. In all modes, before discharging to the main stack the offgas passes through a parallel set of HEPA filters.

This system uses a catalytic recombiner to recombine hydrogen and oxygen from the radiolytic dissociation of reactor coolant and other sources. After the recombiner, the offgas is cooled by two condensers in series and then delivered to one of two dryers to reduce the moisture content before being passed through the charcoal beds for delay and decay of noble gas activity. The radioactivity of the gaseous mixture is monitored at the discharge of the SJAE and in the main stack.

APPLICABLE SAFETY ANALYSES

The main condenser offgas gross gamma activity rate is an initial condition of the Main Condenser SJAE Offgas System failure event, discussed in the UFSAR, Section 11.4.7.2 (Ref. 1). The analysis assumes a gross failure in the Main Condenser SJAE Offgas System that results in the rupture of the Main Condenser SJAE Offgas System pressure boundary. The gross gamma activity rate is controlled to ensure that, during the event, the calculated offsite doses will be well within the limits of 10 CFR 100 (Ref. 2).

The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

(continued)

BASES (continued)

LCO

To ensure compliance with the assumptions of the Main Condenser SJAE Offgas System failure event (Ref. 1), the fission product release rate should be consistent with a nominal noble gas release to the reactor coolant. The LCO is established consistent with a nominal production rate of 600,000 μCi/sec with no decay.

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser SJAE Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, main steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment, the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser SJAE Offgas System rupture.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits in the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser SJAE Offgas System from significant sources of radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain primary containment isolation valve is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging plant systems.

An alternative to Required Actions B.1 and B.2 is to place the plant in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The

(continued)

BASES

ACTIONS

B.1, B.2, B.3.1, and B.3.2 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR requires an isotopic analysis of an offgas sample, taken at the discharge (prior to dilution and/or discharge) of the SJAE, to ensure that the required limits are satisfied. If the measured rate of radioactivity increases significantly (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. As noted, this Frequency is only required when the gross gamma activity rate, as indicated by the SJAE monitor, is ≥ 5000 μCi/second. The 5,000 μCi/second threshold level is an administrative control to reduce the number of unnecessary grab samples. This value is approximately 1% of the SJAE trip level setting and operating at or below the threshold level will ensure the site boundary annual radiation exposures remain within the 10 CFR 50, Appendix I guidelines (Ref. 4). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser SJAE Offgas System at significant rates.

REFERENCES

1. UFSAR, Section 11.4.7.2.
2. 10 CFR 100.
3. 10 CFR 50.36(c)(2)(ii).
4. 10 CFR 50, Appendix I.

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during plant startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 25% 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 four valves connected to the main steam lines between the main steam isolation valves and the turbine stop valve chest. Each of these four valves is operated by porting hydraulic fluid to the operating pistons through an electrically positioned servo valve. The bypass valves are controlled by the pressure regulation function of the Turbine Electro-Hydraulic Control (EHC) System, as discussed in the UFSAR, Section 7.11 (Ref. 1). The bypass valves are normally closed, and the EHC 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 EHC controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass manifold, through each bypass valve and associated connecting piping, to a pressure reducer, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during some transients, as discussed in the UFSAR, Section 14.5 (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in MCPR or LHGR penalties. With an inoperable Main Turbine Bypass System, the feedwater controller failure event may become the limiting event.

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

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that

(continued)

BASES

LCO (continued)

cause rapid pressurization, so that the Safety Limit MCPR is not exceeded. With the Main Turbine Bypass System inoperable, modifications to the MCPR operating limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and the LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)") may be applied to allow this LCO to be met. The LHGR limit and MCPR operating limit for the inoperable Main Turbine Bypass System are specified in the COLR, if applicable. An OPERABLE Main Turbine Bypass System requires three of the four bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Ref. 4).

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the applicable safety analyses. As discussed in the Bases for LCO 3.2.2 and LCO 3.2.3, sufficient margin to these limits exists at < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable (two or more bypass valves inoperable), and the LHGR limit and MCPR operating limit for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the LHGR limit and MCPR operating limit 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 LHGR limit and MCPR operating limit for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required

(continued)

BASES

ACTIONS

B.1 (continued)

limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the abnormal operational transients. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

Cycling each required main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The specified Frequency (prior to entering MODE 2 or 3 from MODE 4) is based on engineering judgment, is consistent with the procedural controls governing valve operation, ensures correct valve positions, and ensures the valves are OPERABLE prior to each reactor startup from MODE 4. Operating experience has shown that these components usually pass the SR when performed at the specified 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, the required valves will actuate to their required position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 the Technical Requirements Manual (Reference 5). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. USFAR, Section 7.11.

2. UFSAR, Section 14.5.

3. 10 CFR 50.36(c)(2)(ii).

4. Supplemental Reload Licensing Report for James A. FitzPatrick (Revision specified in the COLR).

5. Technical Requirements Manual.

B 3.7 PLANT SYSTEMS

B 3.7.7 Spent Fuel Storage Pool Water Level

BASES

BACKGROUND	The minimum water level in the spent fuel storage pool ensures that the assumptions of iodine decontamination factors following a refueling accident are met. A general description of the spent fuel storage pool design is found in the UFSAR, Section 9.3 (Ref. 1). The assumptions of the refueling accident are found in the UFSAR, Section 14.6.1.4 (Ref. 2).
APPLICABLE SAFETY ANALYSES	The water level above the irradiated fuel assemblies is an implicit assumption of the refueling accident. A refueling accident is evaluated to ensure that the radiological consequences (calculated whole body and thyroid doses at the exclusion area and low population zone boundaries) are ≤ 25% of 10 CFR 100 (Ref. 3) exposure guidelines NUREG-0800 (Ref. 4). A refueling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in the Regulatory Guide 1.25 (Ref. 5). The refueling accident is evaluated for the dropping of an irradiated fuel assembly onto the reactor core. The consequences of a refueling accident over the spent fuel storage pool are no more severe than those of the refueling accident over the reactor core, as discussed in the UFSAR, Section 14.6.1.1 (Ref. 6). The water level in the spent fuel storage pool provides for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the secondary containment atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a refueling accident. The spent fuel storage pool water level satisfies Criterion 2 and 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 7).
LCO	The specified water level preserves the assumptions of the refueling accident analysis (Ref. 2). As such, it is the minimum required for fuel movement within the spent fuel storage pool.

(continued)

BASES

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel storage pool since the potential for a release of fission products exists.

ACTIONS

A.1

LCO 3.0.3 is not applicable while in MODE 4 and 5. However, because irradiated fuel assembly movement can occur in MODE 1, 2, or 3, Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

When the initial conditions for an accident cannot be met, action must be taken to preclude the accident from occurring. If the spent fuel storage pool level is less than required, the movement of irradiated fuel assemblies in the spent fuel storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR verifies that sufficient water is available in the event of a refueling accident. The water level in the spent fuel storage pool must be checked periodically. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.3.

2. UFSAR, Section 14.6.1.4.

3. 10 CFR 100.

(continued)

BASES

REFERENCES (continued)

4. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 15.7.4, Revision 1, Radiological Consequences of Fuel Handling Accident, July 1981.

5. Regulatory Guide 1.25, Assumptions Used for Evaluating The Potential Radiological Consequences Of A Fuel Handling Accident In The Fuel Handling And Storage Facility For Boiling And Pressurized Water Reactors, March 1972.

6. UFSAR, Section 14.6.1.1.

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

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources-Operating

BASES

BACKGROUND

The AC Sources for the plant Class 1E AC Electrical Power Distribution System consist of the Main Generator (normal), 115 kV transmission network (reserve), 345 kV transmission network (backfeed, which is only available with the main generator offline and the links removed), and emergency diesel generators (EDGs) A, B, C, and D (onsite). As required by JAFNPP design criteria (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safeguards 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 the normal main generator source, two 115 kV transmission network sources through the associated reserve circuits, one EDG subsystem onsite source consisting of two EDGs, and the 345 kV transmission network backfeed (which is only available with the main generator offline and the links removed) source.

Offsite power is supplied to the 115 kV and 345 kV switchyards from the transmission network by four transmission lines. The 115 kV switchyard is supplied by two independent 115 kV transmission lines and associated breakers. One transmission line, the Lighthouse Hill-FitzPatrick line 3 (breaker 10022), connects the South 115 kV bus to the Lighthouse Hill substation. The other transmission line, Nine Mile-FitzPatrick line 4 (breaker 10012), connects the North 115 kV bus to the Nine Mile Point Unit One Nuclear Station 115 kV switchyard which is then connected to the South Oswego substation. The South 115 kV bus and the North 115 kV bus are connected by a normally closed electrically operated disconnect (10017). Each circuit breaker and disconnect is provided with two complete sets of protective relaying for tripping. In the event of a fault on a 115 kV bus the associated breaker and disconnect will open to de-energize the bus and isolate the faulted bus section. The 115 kV reserve power source is stepped down to 4.16 kV by Reserve Station Service Transformers (RSSTs) 71T-2 and 71T-3. The Reserve Station Service Transformers, 71T-2 and 71T-3, are provided with a load tap changer. These load tap changers provide voltage regulation in the event of changing 115 kV transmission system voltages when the facility is connected to this source of offsite power. These load tap changers can be operated in manual or automatic mode. RSST 71T-2 supplies 4.16 kV buses 10200, 10400, and 10600 for plant startup and shutdown.

(continued)

BASES

BACKGROUND (continued)

RSST 71T-3 supplies 4.16 kV buses 10100, 10300, and 10500 for plant startup and shutdown. The lines connecting the RSSTs to the 115 kV transmission lines are arranged so that a failure of either line does not result in the loss of the other line. The 345 kV switchyard is connected to National Grid's Edic and Scriba Substations. The Main Generator provides power at 24 kV to two main transformers (T1A and T1B) connected in parallel, and to the Normal Station Service Transformer (NSST) 71T-4. NSST 71T-4 steps down voltage to supply power to the 4.16 kV buses 10100, 10200, 10300, 10400 and 10700. Normal (from the Main Generator) or reserve power is supplied to emergency buses 10500 and 10600 through tie connections from buses 10300 and 10400, respectively. If normal power from NSST 71T-4 is lost, the reserve power, RSSTs 71T-2 and 71T-3, will automatically energize all plant buses via the fast or residual transfer, except bus 10700. The only power source to bus 10700 is NSST 71T-4 because the bus has no connected loads necessary for startup or safe shutdown of the plant. If the RSSTs were to fail, the EDG subsystems would automatically energize their respective buses. The 345 kV switchyard is sometimes used to backfeed NSST 71T-4. This operation requires the main generator links to be manually disconnected and therefore can only be used during plant outages. A detailed description of the 115 kV and 345 kV transmission networks and the normal, reserve, and backfeed AC power supply circuits to the plant Class 1E emergency buses is found in the UFSAR, Chapter 8 (Ref. 2).

A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the 115 kV transmission network source to the plant Class 1E emergency bus or buses. During normal plant operation, with the main generator on line, emergency buses 10500 and 10600 are energized by the normal AC power source from NSST 71T-4 via buses 10300 and 10400, respectively. Loss or degradation of the normal AC power source results in an automatic fast transfer or automatic residual transfer to the reserve AC power source through RSSTs 71T-2 and 71T-3. The load tap changer controller and backup controller settings have been selected to maintain the 115 kV offsite power to the JAF facility under various analyzed scenarios. Each RSST is sized to supply all loads on its associated emergency and non-emergency service buses.

The onsite standby AC power sources for 4.16 kV emergency buses 10500 and 10600 consist of two independent and redundant EDG subsystems that are self contained and independent of normal, backfeed, and reserve sources. Each EDG subsystem consists of two EDGs which operate in parallel and are dedicated to an emergency power division (1 or 2).

(continued)

BASES

BACKGROUND (continued)

The Division 1 EDG subsystem consists of EDGs A and C and is dedicated to emergency bus 10500. The Division 2 EDG subsystem consists of EDGs B and D and is dedicated to emergency bus 10600. The EDGs start automatically on an emergency bus degraded voltage signal. an emergency bus undervoltage (LOP) signal, or a loss of coolant accident (LOCA) signal (i.e., low-low-low reactor water level signal or high drywell pressure signal). As a consequence of a LOP or degraded voltage signal, independent of or coincident with a LOCA signal, the emergency bus undervoltage control logic starts the EDGs. Coincident with the EDG starting and force paralleling, the emergency bus undervoltage control logic trips the 4.16 kV emergency bus tie breakers, trips the emergency bus load breakers (except for the 600 V emergency substations), and provides a close permissive signal to the EDG output breakers. The EDGs are automatically tied to their respective emergency buses and if a LOCA condition exists loads are sequentially connected to the emergency buses by the programmed restart time delay relays. The programmed restart time delay relays control the permissive and starting signals to motor breakers to prevent overloading the EDGs. On a LOCA signal alone the EDGs start, force parallel, and operate in the standby mode without tying to the emergency bus.

Certain required plant loads are returned to service in a predetermined sequence in the presence of a LOCA signal in order to prevent overloading of the EDGs in the process. Within approximately 27 seconds after the initiating signal is received, all automatic and permanently connected loads needed to recover the plant or maintain it in a safe condition are returned to service. While each emergency power division is designed to be supplied by an EDG pair, if an EDG were to fail during a LOCA event in conjunction with a LOP, the programmed restart logic will not start the second residual heat removal pump powered from the 4.16 kV emergency bus associated with the failed EDG so that the remaining EDG in that EDG subsystem is not overloaded.

Ratings for the EDGs satisfy the requirements of Safety Guide 9 (Ref. 3). EDGs A, B, C and D have the following ratings:

a. 2600 kW - continuous,

b. 2850 kW - 2000 hours,

c. 2950 kW - 160 hours,

d. 3050 kW - 30 minutes.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume Engineered Safeguards 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 engineered safeguards 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 3.5, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling (RCIC) System; 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 plant. This includes maintaining the onsite (EDGs) or qualified offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single active component failure.

AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the plant Class 1E Distribution System and two separate and independent EDG subsystems each consisting of two EDGs ensure maintain it in a safe shutdown condition after an abnormal operational transient or a postulated DBA, availability of the required power to shut down the reactor and Qualified offsite circuits are those that are described in the UFSAR, and are part of the licensing basis for the plant.

Each qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the emergency buses. Each qualified offsite circuit consists of the incoming disconnect device to reserve station service transformer (RSST) 71T-2 or 71T-3, the associated RSST, (including the load tap changer, while in automatic or manual mode of operation) and the respective circuit path including feeder breakers to the 4.16 kV emergency bus 10500 or 10600. If one 115 kV transmission line is inoperable, then one of the offsite circuits must be declared inoperable. In addition, to ensure a fault on one qualified offsite circuit does not adversely impact the other qualified

(continued)

BASES

LCO (continued)

offsite circuit, the 115 kV North and South bus disconnect (10017) automatic opening feature must be OPERABLE if the disconnect is closed. If the automatic opening feature is inoperable, then one of the offsite circuits must be declared inoperable. In addition, due to the unique nature of this design, the automatic opening feature is periodically demonstrated in accordance with plant procedures.

Each EDG subsystem must be capable of starting, accelerating to rated speed and voltage. force paralleling and connecting to its respective emergency bus on detection of bus undervoltage. This sequence must be accomplished within 11 seconds. Each EDG subsystem 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 emergency buses. These capabilities are required to be met with the EDGs in standby condition. Additional EDG capabilities must be demonstrated to meet required Surveillances. e.g ., capability of each EDG subsystem to reject a load greater than or equal to the load of a core spray pump. Proper sequencing of loads, including tripping of nonessential loads, is a required function for EDG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the EDGs, the separation and independence are complete. For the qualified offsite AC sources, the separation and independence are to the extent practical. A qualified offsite circuit that is not connected to an emergency bus is required to have OPERABLE automatic transfer interlock mechanisms to its associated emergency bus to support OPERABILITY of that circuit.

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 abnormal operational transients; and

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

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

(continued)

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable EDG subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable EDG subsystem 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.

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 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 offsite circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the division cannot be powered from an offsite source, is intended to provide assurance that an event with a coincident single active failure of the associated EDG subsystem does not result in a complete loss of safety function of critical redundant required features. These redundant required features are those that are assumed in the safety analysis to function to mitigate an accident, coincident with a loss of offsite power, such as the Emergency Core Cooling Systems (ECCS). These redundant required features do not include monitoring requirements, such as Post Accident Monitoring Instrumentation and Remote Shutdown System. 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 no power from an offsite circuit.

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:

(continued)

BASES

ACTIONS

A.2 (continued)

a. The division has no offsite circuit OPERABLE to supply its loads; and

b. A redundant required feature on the other division is inoperable.

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

Discovering no offsite power to one 4.16 kV emergency bus of the plant 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 plant is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuit and EDGs are adequate to supply electrical power to the plant Class 1E Distribution System. Thus, on a component basis, single active failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

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 EDGs are adequate to supply electrical power to the plant Class 1E Distribution System.

The 7 day Completion Time takes into account the redundancy, capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with one EDG subsystem inoperable, it is necessary to verify the availability of the 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 an EDG subsystem is inoperable, does not result in a complete loss of safety function of critical redundant required features. These redundant required features are those that are assumed in the safety analysis to function to mitigate an accident, such as ECCS. These redundant required features do not include monitoring requirements, such as Post Accident Monitoring Instrumentation and Remote Shutdown System. These features are designed with redundant safety related divisions (Le., 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 EDG subsystem.

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 EDG subsystem exists; and

b. A redundant required feature on the other division is inoperable.

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

Discovering one EDG subsystem inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE EDG subsystem 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 plant to transients associated with shutdown.

(continued)

BASES

ACTIONS

B.2 (continued)

The remaining OPERABLE EDG subsystem and offsite circuits are adequate to supply electrical power to the plant Class 1E Distribution System. Thus, on a component basis, single active 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 the OPERABLE EDG subsystem. If it can be determined that the cause of the inoperable EDG subsystem does not exist on the OPERABLE EDG subsystem, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other EDG subsystem, the EDG subsystem is declared inoperable upon discovery, and Condition E of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable EDG subsystem cannot be confirmed not to exist on the remaining EDG subsystem, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of the remaining EDG subsystem.

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

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the remaining OPERABLE EDG subsystem is not affected by the same problem as the inoperable EDG.

B.4

The design of the AC Sources allows operation to continue in Condition B for a period that should not exceed 14 days. In Condition B, the remaining OPERABLE EDG subsystem and offsite circuits are adequate to supply electrical power to the plant Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the, remaining AC sources, reasonable

(continued)

BASES

ACTIONS

B.4 (continued)

time for repairs, and low probability of a DBA occurring during this period. In addition, the 14 day completion time is based on a risk-informed assessment of the EDG subsystem inoperability. EDG subsystem inoperability and the simultaneous inoperability of other plant equipment is assessed in accordance with Specification 5.5.13, Configuration Risk Management Program (CRMP).

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required features. These redundant required features are those that are assumed in the safety analysis to function to mitigate an accident, coincident with a loss of offsite power, such as ECCS. These redundant required features do not include monitoring requirements, such as Post Accident Monitoring Instrumentation and Remote Shutdown System. These features are designed with redundant safety related divisions, (i.e., single division systems are not included in the list). Redundant required features failures consist of any of these features that are inoperable because any inoperability is on a division redundant to a division with inoperable offsite circuits. The Completion Time for taking these actions is reduced to 12 hours from that allowed with one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that a Completion Time of 7 days for two required offsite circuits inoperable is acceptable based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. Both offsite circuits are inoperable; and

b. A redundant required feature is inoperable.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Operation may continue in Condition C for a period that should not exceed 7 days. 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 reserve 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 EDG subsystems inoperable. However, two factors tend to decrease the severity of this degradation level:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the offsite circuits inoperable, sufficient onsite AC sources are available to maintain the plant 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 active component failure were postulated as a part of the design basis in the safety analysis. The 7 day Completion Time in Required Action C.2 provides a period of time to effect restoration of both offsite circuits commensurate with the importance of maintaining AC electrical power system capable of meeting its design criteria.

With both offsite circuits inoperable, operation may continue for 7 days. In this situation Conditions A and C must be entered concurrently. If both offsite circuits are restored within 7 days, unrestricted operation may continue. If only one offsite source is restored within 7 days. Entry into Condition F is required. If the offsite circuits were not found to be inoperable concurrently, the Completion Time of Required Action A.3 must be met for the first inoperable circuit in accordance with the guidance of Section 1.3 (Completion Times). This will ensure that the maximum time two offsite circuits could be inoperable simultaneously without entering Condition F is limited.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution Systems-Operating 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 4.16 kV emergency 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 EDG subsystem without regard to whether a division is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized division.

According to recommendations in Regulatory Guide 1.93 (Ref. 8), 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 power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both 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 EDG subsystems inoperable, there is no remaining onsite AC source. Thus, with an assumed loss of offsite electrical power, insufficient onsite AC sources are available to power the minimum required engineered safeguards functions. Since the offsite electrical power system is the only source of AC power for the majority of engineered safeguards 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 Main 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 the recommendations in Regulatory Guide 1.93 (Ref. 8), with both EDG subsystems inoperable, operation may continue for a period that should not exceed 2 hours.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If the inoperable AC electrical power sources 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.

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. Entry into Condition G is necessary when both offsite circuits and one EDG subsystem are inoperable (where the EDG subsystem is inoperable due to an inoperability of one or both EDGs within the EDG subsystem), both EDG subsystems and one offsite circuit are inoperable, or both offsite circuits and both EDG subsystems are inoperable. 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 plant 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 Reference 1. Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the EDG subsystems are in general conformance with the recommendations of Safety Guide 9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10).

Where the SRs discussed herein specify steady state voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3900 V is approximately 94% of the nominal 4160 V output voltage. This value, which is slightly greater than that specified in ANSI C84.1 (Ref. 11), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 EDG 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 Safety Guide 9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the plant distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that emergency buses and loads can be or are connected to their offsite power source and that appropriate independence of offsite circuits is maintained. Offsite circuit alignment verification can be accomplished by verifying that an offsite circuit bus is energized and that the status of offsite circuit supply breakers and disconnects displayed in the control room is correct. Offsite source power availability can be verified by communication with Niagara Mohawk for the Nine Mile Point Unit One switchyard, South Oswego substation, and Light House Hill substation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.2

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

To minimize the wear on moving parts, this SR has been modified by a Note to indicate that all EDG starts for this Surveillance may be preceded by an engine prelube period and followed by a warmup prior to loading.

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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 (continued)

This SR requires that the EDG subsystem starts from standby conditions, force parallels, and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions in the design basis LOCA analysis of UFSAR, Section 6.5 (Ref. 12).

In addition to the SR requirements, the time for the EDG subsystem to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.3

This SR verifies that the EDG subsystems 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 EDG subsystem is paralleled with the normal, reserve or backfeed power source.

Although no power factor requirements are established by this SR, the EDG 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 EDG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

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

Note 3 indicates that this SR should be conducted on only one EDG subsystem at a time in order to avoid common cause failures that

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

might result from normal, reserve or backfeed power source perturbations.

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

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which the low level alarm is annunciated. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1.5 hours of EDG operation at full load.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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. Periodic removal of water from the fuel oil day tanks 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 EDG 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 Frequency is controlled under the Surveillance Frequency Control Program. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This SR demonstrates that at least one fuel oil transfer pump associated with each OPERABLE EDG operates and automatically transfers fuel oil from its associated storage tank to its associated day tank. It is required to support continuous operation of onsite power sources. This Surveillance provides assurance that the fuel oil transfer

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

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 for each EDG.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.7

Automatic residual transfer of each 4.16 kV emergency bus power supply from the normal (main generator) source (NSST 71T-4) to each offsite circuit demonstrates the OPERABILITY of the offsite circuit distribution network to power the shutdown loads. As Noted, the SR is only required to be met for each offsite circuit that is not energizing its respective 4.16 kV emergency bus (i.e., the bus is being energized by the NSST), since the automatic transfer must be OPERABLE when the 4.16 kV emergency bus is being supplied by the main generator. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

In lieu of an actual automatic residual transfer, testing that adequately demonstrates the automatic residual transfer capability is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire automatic residual transfer function and emergency bus energization is verified.

SR 3.8.1.8

Each EDG 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 EDG subsystem capability to reject the largest single load without exceeding a predetermined frequency and while maintaining a specified margin to the overspeed trip. The largest single load for each EDG subsystem is a core spray pump (1250 bhp motor rating actual load will depend on accident progression). This Surveillance may be accomplished by:

a. Tripping the EDG output breakers with the EDG subsystem carrying greater than or equal to its associated single largest post-accident load while paralleled with normal, reserve, or backfeed power, or while solely supplying the bus; or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

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

Consistent with Safety Guide 9 (Ref. 3), the load rejection test is acceptable if the diesel speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal speed, whichever is lower.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. In order to ensure that the EDG subsystem is tested under load conditions that are as close to design basis conditions as possible, the Note requires that, if paralleled with normal, reserve or backfeed power, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the EDG subsystem would experience. However, if the grid conditions do not permit, the power factor limit is not required to be met. In this condition the test is performed with a power factor as close to the design rating of the machine as practicable. This is permitted since, with a high grid voltage it may not be possible to raise the EDG subsystem output voltage sufficiently to obtain the required power factor without creating an overvoltage condition on the emergency bus.

SR 3.8.1.9

Consistent with Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), this SR demonstrates the as designed operation of the onsite power sources due to an emergency bus loss of power (LOP) signal. This test verifies all actions required following receipt of the LOP signal, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the EDG subsystem. It further demonstrates the capability of the EDG subsystem to automatically achieve the required voltage and frequency within the specified time.

The EDG auto-start time of 11 seconds is derived from requirements of the 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

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 EDG subsystem loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or 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 EDG subsystem to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is to minimize the wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

SR 3.8.1.10

This SR demonstrates that the EDG subsystem automatically starts, force parallels 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 3.8.1.10.d and SR 3.8.1.10.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a LOCA signal without a LOP signal.

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 connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the EDG subsystem 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.

In addition to the SR requirements, the time for the EDG subsystem to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is to minimize the wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

SR 3.8.1.11

Consistent with IEEE-387 (Ref. 13), Section 7.5.9 and Table 3, this SR requires demonstration that the EDGs can run continuously at full load capability for an interval of not less than 8 hours- 6 hours of which is at a load equivalent to 90-100% of the continuous rating of the EDG, and 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating of the EDG. The EDG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the EDG subsystem is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the EDG subsystem could experience. A load band is provided to avoid routine overloading of the EDG subsystem. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 2 is provided in recognition that when grid conditions do not permit, the power factor limit is not required to be met. In this condition, the test is performed with a power factor as close to the design rating of the machine as practicable. This is permitted since, with a high grid voltage it may not be possible to raise the EDG output voltage sufficiently to obtain the required power factor without creating an overvoltage condition on the emergency bus.

SR 3.8.1.12

In the event of a DBA coincident with an emergency bus loss of power signal, the EDGs are required to supply the necessary power to Engineered Safeguards systems so that the fuel, RCS, and containment design limits are not exceeded.

This SR demonstrates EDG subsystem operation, as discussed in the Bases for SR 3.8.1.9, during an emergency bus LOP 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 EDG subsystem to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is to minimize the wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

Under accident conditions loads are sequentially connected to the bus by the individual time delay relays. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the EDGs due to high motor starting currents. The minimum load sequence time interval tolerance ensures that sufficient time exists for the EDG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding engineered safeguards equipment time delays are not violated. There is no upper limit for the load sequence time interval since, for a single load interval (i.e., the time between two load blocks), the capability of the EDG to restore frequency and voltage prior to applying the second load is not negatively affected by a longer than designed load interval, and if there are additional load blocks (i.e., the design includes multiple load intervals), then the lower limit requirements will ensure that sufficient time exists for the EDG to restore frequency and voltage prior to applying the remaining load blocks (i.e., all load intervals must be greater than or equal to the minimum design interval).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Chapter 8.
3. Safety Guide 9, Selection Of Diesel Generator Set Capacity For Standby Power Supplies, March 1971.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 14.
6. 10 CFR 50.36(c)(2)(ii).
7. Generic Letter 84-15, Proposed Staff Actions To Improve And Maintain Diesel Generator Reliability, July 1984.
8. Regulatory Guide 1.93, Availability Of Electric Power Sources, December 1974.
9. Regulatory Guide 1.108, Revision 1, Periodic Testing of Diesel Generator Units Used As Onsite Electric Power Systems At Nuclear Power Plants, August 1977.

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BASES

REFERENCES (continued)

10. Regulatory Guide 1.137, Revision 1, Fuel-Oil Systems for Standby Diesel Generators, October 1979.

11. ANSI C84.1, Voltage Ratings for Electric Power Systems and Equipment, 1982.

12. UFSAR, Section 6.5.

13. IEEE-387, IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations, 1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources - Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources-Operating." In addition to the reserve AC sources described in LCO 3.8.1, during plant shutdown with the main generator off line, the plant emergency buses may be supplied using the 345 kV (backfeed) AC source. The 345 kV backfeed requires removing the main generator disconnect links that tie the main generator to the 24 kV bus, and providing power from the 345 kV transmission network to energize the main transformers (T1A and T1B), 24 kV bus, normal station service transformer (NSST) 71T-4, and subsequent 4.16 kV distribution and emergency buses. The 345 kV offsite backfeed AC source as well as the two (2) 115 kV offsite circuits are the qualified offsite circuits during outages.

APPLICABLE SAFETY ANALYSIS

The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the plant status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, AC electrical power is only required to mitigate fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

In general, when the plant is shutdown the Technical Specifications requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents. However, assuming a single active component failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Postulated worst case bounding events are deemed not credible in

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

MODES 4 and 5 because the energy contained within the reactor coolant pressure boundary (RCPB). reactor coolant temperature and pressure, and corresponding stresses result in the probabilities of occurrences significantly reduced or eliminated. and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1. 2. and 3. various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted. provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODES 1, 2. and 3 LCO requirements are acceptable during shutdown MODES. based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as an economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operation MODE analyses, or both.

c. Prudent consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical. the ability to perform required functions (even if not meeting MODES 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown. this LCO ensures the capability of supporting systems necessary for avoiding immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (emergency diesel generator (EDG)) power.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 1).

(continued)

BASES (continued)

LCO

One qualified offsite circuit capable of supplying one division of the plant Class IE AC power distribution subsystem(s) of LCD 3.8.8, "Distribution Systems -Shutdown," and one qualified offsite circuit, which may be the same circuit required above, capable of supplying the other division of the plant Class IE AC power distribution subsystem(s) when a second division is required by LCD 3.8.8, ensures that all required loads are powered from offsite power. An OPERABLE EDG subsystem, associated with a 4.16 kV emergency bus required OPERABLE by LCD 3.8.8, ensures that a diverse power source is available for providing electrical power support assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and EDG subsystem ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the conseguences of postulated events during shutdown (e.g., fuel handling accidents involving handling recently). Automatic initiation of the required EDG during shutdown conditions is specified in LCO 3.3.5.1, "ECCS Instrumentation," and LC 3.3.8.1, "LOP Instrumentation."

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to its respective 4.16 kV emergency bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in LCO 3.8.1 Bases and the UFSAR and are part of the licensing basis for the plant. However, since the plant is shutdown, when two offsite circuits are required, they may share one of the incoming switchyard breakers provided the North and South bus disconnect is closed. Also, while in this condition, the automatic opening feature of the disconnect is not required to be OPERABLE. This is allowed since the two offsite circuits are not required to be independent while shutdown.

The required EDG subsystem must be capable of starting, accelerating to rated speed and voltage, force paralleling, and connecting to its respective emergency bus on detection of bus undervoltage. This sequence must be accomplished within 11 seconds. The required EDG subsystem 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 emergency buses. These capabilities are required to be met with the EDG subsystem in standby condition.

Proper sequencing of loads. including tripping of nonessential loads. is a required function for EDG subsystem OPERABILITY. The necessary portions of the Emergency Service Water System and Ultimate Heat Sink are also required to provide appropriate cooling to

(continued)

BASES

LCO (continued)

the required EDG subsystem. In addition. proper sequence operation is an integral part of offsite circuit OPERABILITY since its inoperability impacts the ability to start and maintain energized loads required OPERABLE by LCO 3.8.8.

No automatic transfer capability is required for offsite circuits to be considered OPERABLE.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the secondary containment to provide assurance that:

a. Systems that provide core cooling are available;

b. Systems needed to mitigate a fuel handling accident involving handling recently irradiated fuel (i.e .• fuel that has occupied part of a critical reactor core within the previous 96 hours) are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition or refueling condition.

AC power requirements for MODES 1. 2. and 3 are covered in LCO 3.8.1.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However. since recently irradiated fuel assembly movement can occur in MODE 1. 2. or 3. the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5. LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1. 2. or 3. The fuel movement is independent of reactor operations. Entering LCO 3.0.3. while in MODE 1. 2. or 3 would require the unit to be shutdown unnecessarily.

A.1

An offsite circuit is considered inoperable if it is not available to one required 4.16 kV emergency bus. If two 4.16 kV emergency buses are required per LCO 3.8.8, one division with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, and recently irradiated fuel

(continued)

BASES

LCO (continued)

A.1 (continued)

movement. By the allowance of the option to declare required features inoperable with no offsite power, appropriate restrictions can be implemented in accordance with the affected required feature(s) LCOs' ACTIONS. These required features are those that are assumed in the safety analysis to function to mitigate events postulated during shutdown, such as an inadvertent draindown of the reactor vessel or a fuel handling accident involving recently irradiated fuel. These required features do not include monitoring requirements.

A.2.1, A.2.2, A.2.3, B.1, B.2, and B.3

With an offsite circuit not available to all required 4.16 kV emergency buses, the option still exists to declare all required features inoperable per Required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required EDG subsystem inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, and movement of recently irradiated fuel assemblies in the secondary containment.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required 4.16 *kV* emergency bus, ACTIONS for LCO 3.8.8 must be immediately entered. This Note allows Condition A to provide requirements for the loss of an offsite circuit whether or not a division is de-energized. LCO 3.8.8 provides the appropriate restrictions for the situation involving a de-energized division.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.7 is not required to be met since the main generator is not used to provide AC power while shutdown. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE EDG subsystem from being paralleled with the reserve power network or otherwise rendered inoperable during the performance of SRs, and to preclude de-energizing a required 4.16 *kV* emergency bus or disconnecting a required reserve circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required reserve circuit and EDG subsystem. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the EDG subsystem and reserve circuit is required to be OPERABLE.

Note 2 states that SRs 3.8.1.10 and 3.8.1.12 are not required to be met when its associated ECCS subsystem(s) are not required to be OPERABLE. These SRs demonstrate the EDG response to an ECCS signal (either alone or in conjunction with a loss of power signal). This is consistent with the ECCS instrumentation requirements that do not require the ECCS signal when the ECCS System is not required to-be OPERABLE.

REFERENCES

1. 10 CFR 50.36(c)(2)(ii).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each emergency diesel generator (EDG) subsystem is provided with two fuel oil storage tanks. Each storage tank has a fuel oil capacity sufficient to operate one EDG for a period of 7 days while the EDG is supplying full load. The maximum post loss of coolant accident (LOCA) load demand discussed in UFSAR, Section 8.6.2 (Ref. 1) is calculated using the assumption that at least two EDGs are operating. This onsite fuel oil capacity is sufficient to operate the EDGs for longer than the time to replenish the onsite supply from outside sources.

Normally fuel oil is transferred from storage tanks to day tanks by either of two transfer pumps associated with each storage tank. In addition the fuel oil transfer pumps can be manually aligned to permit fuel oil transfer, within the EDG subsystem, from either of the two fuel oil storage tanks to either of the two fuel oil day tanks. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one EDG. All fuel oil storage tanks are located underground. Fuel oil day tanks and transfer pumps are located in the associated EDG room.

For proper operation of the EDGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) and ANSI N195 (Ref. 3) address recommended fuel oil practices, as modified by 1) the ACTIONS and Surveillance Requirements (SRs) of Specification 3.8.3, and 2) the Bases for SR 3.8.3.3, which specifies the current fuel oil testing standards. The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (absolute specific gravity or API gravity), and impurity level.

The EDG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated EDG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. The engine oil sump is sufficient to ensure 7 days' continuous

(continued)

BASES

BACKGROUND (continued)

operation. This supply is sufficient to operate the EDGs for longer than the time to replenish the onsite lube oil supply from outside sources. Each EDG has an air start system with adequate capacity for five successive starts on the EDG without recharging or realigning the air start receivers. Each EDG air start system consists of piping and valves which supply all associated EDG air start motors simultaneously when aligned to one of two sets of 5 air start receivers.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 14 (Ref. 4), assume Engineered Safeguards systems are OPERABLE. The EDGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to Engineered Safeguards systems so that fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and starting air subsystems support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of EDGs required to shut down the reactor and to maintain it in a safe condition for an abnormal operational transient or a postulated DBA with loss of power. EDG day tank fuel oil requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown."

The starting air system is required to have a minimum capacity for five successive EDG starts without recharging or realigning the air start receivers.

(continued)

BASES (continued)

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an abnormal operational transient or a postulated DBA. Because stored diesel fuel oil, lube oil, and starting air subsystems support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated EDG subsystem is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each EDG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable EDG. Complying with the Required Actions for one inoperable EDG may allow for continued operation, and subsequent inoperable EDG(s) governed by separate Condition entry and application of associated Required Actions.

A.1

With fuel oil level less than the level shown in Table B 3.8.3-1 in a storage tank, the 7 day fuel oil supply for an EDG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply as shown in Table B 3.8.3-2. These circumstances may be caused by events such as:

a. Full load operation required for an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the EDG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that action will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

B.1

With lube oil inventory < 168 gal, sufficient lube oil to support 7 days of continuous EDG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply (144 gal). This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the EDG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that action will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated EDG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the EDG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combination of these procedures. Even if an EDG start and load was required during this

(continued)

BASES

ACTIONS

D.1 (continued)

time interval and the fuel oil properties were outside limits, there is high likelihood that the EDG would still be capable of performing its intended function. If the new fuel oil has not yet been added to the fuel oil storage tanks, entry into this condition is not necessary.

E.1

With required starting air receiver pressure < 150 psig, sufficient capacity for five successive EDG starts does not exist. However, as long as the receiver pressure is ≥ 110 psig, there is adequate capacity for at least one start, and the EDG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the EDG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most EDG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time of Condition A, B, C, D, or E not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A, B, C, D, or E, the associated EDG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each EDG's operation for 7 days at full load. The fuel oil level equivalent to a 7 day supply in gallons when calculated in accordance with References 2, 7, and 8 is shown in Table B 3.8.3-1. The 7 day period is sufficient time to place the plant in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.2

This SR ensures that sufficient lubricating oil inventory is available to support at least 7 days of full load operation for each EDG. The lube oil equivalent to a 7 day supply is 168 gallons. The 168 gal requirement is based on the EDG manufacturer's consumption values for the run time of the EDG. Oil in the EDG lube oil sump is adequate for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between the sample (and corresponding test results) of new fuel and addition of new fuel oil to the storage tanks to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-1995 (Ref. 6);

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

b. Verify in accordance with the tests specified in ASTM D975-2006 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27° and ≤ 39°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes, and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-1993 or verify water and sediment are within ASTM D975-2006 limits when tested in accordance with, ASTM D2709, or ASTM D1796 (Ref 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Following the initial new fuel oil sample, the fuel oil is analyzed within 31 days following addition of the new fuel oil to the fuel oil storage tanks to establish that the other properties specified in Table 1 of ASTM D975-2006 (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-2006 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-1995 (Ref. 6) or ASTM D2622-1994 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on EDG operation. This Surveillance ensures the availability of high quality fuel oil for the EDGs.

Fuel oil degradation during long term storage shows up as an increase in particulate concentration, mostly due to oxidation. The presence of particulates does not mean that the fuel oil will not burn properly in a diesel engine. The particulates can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D6217-1998 (Ref. 6), except that the specified filters may be replaced with filters up to 3.0 microns. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This SR ensures that, without the aid of the refill compressor, sufficient air start capacity for each EDG is available. The system design requirements provide for a minimum of five engine start cycles without recharging or realigning air start receivers. For the purposes of the air start system, a start cycle is defined as the period required from a start signal until the engine speed reaches 200 rpm (the point at which the air start system valves are signaled to close). The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Periodic removal of water from the fuel storage tanks 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 EDG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 2) as supplemented by ANSI/ANS-59.51 (formerly

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.5 (continued)

ANSI N195, Ref. 3). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 8.6.2.

2. Regulatory Guide 1.137, Revision 1, Fuel-Oil Systems For Standby Diesel Generators, October 1979.

3. ANSI N195, Appendix B, 1976.

4. UFSAR, Chapter 14.

5. 10 CFR 50.36(c)(2)(ii).

6. ASTM Standards: D4057-1995, Standard Practice for Manual Sampling of Petroleum and Petroleum Products; D975-2006, Standard Specification for Diesel Fuel Oils; D4176-1993, Standard Test Method for Free Water and Particulate Contamination in Distillate Fuels (Visual Inspection Procedures); D1552-1995, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method); D2622-1994, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry; D6217-1998, Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration; ASTM D2709-1996, Test Method for Water and Sediment in Distillate Fuels by Centrifuge; and ASTM D1796-2004, Standard Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure).

7. ANSI/ANS-59.51 1997, Fuel Oil Systems for Safety Related Emergency Diesel Generators.

8. JAF-CALC-07-00020, Revised Emergency Diesel Generator (EDG) Fuel Oil Storage Quantities for 7 Day and 6 Day Supplies.

Table B 3.8.3-1 (page 1 of 1)
7-Day EDG Fuel Oil Supply

API Gravity	EDG "A" Fuel Oil Storage Tank Level (in Gallons)	EDG "B" Fuel Oil Storage Tank Level (in Gallons)	EDG "C" Fuel Oil Storage Tank Level (in Gallons)	EDG "D" Fuel Oil Storage Tank Level (in Gallons)
39	33,929	34,261	34,188	34,232
36	33,486	33,818	33,745	33,789
33	33,047	33,379	33,306	33,350
30	32,613	32,945	32,872	32,916
27	32,184	32,516	32,443	32,487

Table B 3.8.3-2 (page 1 of 1)
6-Day EDG Fuel Oil Supply

API Gravity	EDG "A" Fuel Oil Storage Tank Level (in Gallons)	EDG "B" Fuel Oil Storage Tank Level (in Gallons)	EDG "C" Fuel Oil Storage Tank Level (in Gallons)	EDG "D" Fuel Oil Storage Tank Level (in Gallons)
39	29,291	29,623	29,550	29,594
36	28,912	29,244	29,171	29,215
33	28,536	28,868	28,795	28,839
30	28,164	28,496	28,423	28,467
27	27,796	28,128	28,055	28,099

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The plant DC electrical power system consists of, the Class 1E, 125 VDC Power System, and the 419 VDC low pressure coolant injection (LPCI) MOV independent power supply subsystems.

The 125 VDC Power System provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment. As required by JAFNPP design criteria (Ref. 1), the 125 VDC Power System is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The 125 VDC Power System also conforms to the recommendations of Safety Guide 6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC power sources provide both motive and control power to selected safety related equipment, as well as circuit breaker control power for the nonsafety related 4160 V and selected 600 V AC distribution systems. Each 125 VDC subsystem is energized by one 125 VDC battery and one 125 VDC battery charger. Each battery is exclusively associated with a single 125 VDC bus. Each battery charger is exclusively associated with a 125 VDC subsystem and cannot be interconnected with any other 125 VDC subsystem. The chargers are supplied from the same AC load groups for which the associated 125 VDC subsystem supplies the control power. The loads between the redundant 125 VDC subsystem are not transferable except for the Automatic Depressurization System (ADS). The ADS valve solenoids are normally fed from the Division 1 125 VDC subsystem and the Division 2 125 VDC subsystem provides a backup. In addition, the Division 1 125 VDC subsystem provides a backup to the Division 2 ADS logic circuits.

The 419 VDC low pressure coolant injection (LPCI) MOV independent power supply subsystems provide the 600 VAC LPCI Independent Power Supply System with a reliable source of power to operate the motor operated valves associated with the LPCI subsystems and provide power to one RCIC pump enclosure exhaust fan via the 600 VAC LPCI independent power supply inverters and associated distribution system. The requirements of these inverters are specified in LCO 3.5.1, "ECCS - Operating." The 419 VDC LPCI MOV independent power supply system consists of two subsystems.

(continued)

BASES

BACKGROUND (continued)

Each 419 VDC LPCI MOV independent power supply subsystem is energized by the associated 419 VDC battery or the associated 419 VDC rectifier/charger. Each battery and rectifier/charger is exclusively associated with a 419 VDC LPCI MOV independent power supply subsystem and cannot be interconnected with the other 419 VDC LPCI MOV independent power supply subsystem.

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In cases where momentary loads are greater than the charger capability, or battery charger output voltage is low, or on loss of normal power to the battery charger, the DC loads are automatically powered from the batteries. Also, on a LPCI automatic actuation signal, the 419 VDC rectifier/charger AC input contactors will open and the 600 VAC LPCI independent power supply inverters will be powered from the 419 VDC LPCI MOV independent power supply batteries.

The DC power distribution system is described in more detail in Bases for LCO 3.8.7, "Distribution System - Operating," and LCO 3.8.8, "Distribution System - Shutdown."

Each 125 VDC and 419 VDC battery is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from its redundant subsystem to ensure that a single failure in one subsystem does not cause a failure in the redundant subsystem. There is no sharing between redundant subsystems such as batteries, battery chargers, or distribution panels.

Each 125 VDC battery has adequate storage capacity to meet the duty cycle(s) discussed in the UFSAR, Chapter 8 (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors. Each 419 VDC LPCI MOV independent power supply battery has adequate storage capacity for one repositioning of the LPCI subsystem motor operated valves (MOVs) on its respective MOV bus.

The 125 VDC batteries are sized to supply associated DC loads required for safe shutdown of the plant, following abnormal operational transients and postulated accidents, until AC power sources are restored (Ref. 4). The 419 VDC batteries are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage limit for

(continued)

BASES

BACKGROUND (continued)

each 125 VDC battery is established in References 10 and 11. The minimum design voltage limit of each 419 VDC LPCI MOV independent power supply battery is established in Reference 12.

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 124 V for a 60 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.07 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage of 2.17 to 2.25 Vpc for the 125 VDC batteries and 2.17 to 2.26 Vpc for the LPCI MOV independent power supply batteries. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage for the 125 VDC batteries is 2.20 Vpc, which corresponds to a total float voltage output of 132 V for a 60 cell battery. The nominal float voltage for the LPCI MOV independent power supply batteries is 2.25 Vpc, which corresponds to a total float voltage output of 418.5 V for a 186 cell battery.

Each 125 VDC and 419 VDC battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each 125 VDC battery charger has sufficient excess capacity to restore the battery after discharging through its duty cycle to its fully charged state while supplying normal control loads (Ref. 4).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle.

(continued)

BASES

BACKGROUND (continued)

Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 5) and Chapter 14 (Ref. 6), assume that Engineered Safeguards systems are OPERABLE. The 125 VDC Power System provides normal and emergency DC electrical power for the EDGs, emergency auxiliaries, and control and switching during all MODES of operation. The 419 VDC LPCI MOV independent power supplies provide normal and emergency power for LPCI MOVs during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all normal and reserve AC power or all onsite AC power; and

b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 7).

LCO

The 125 VDC and 419 VDC LPCI MOV independent power supply subsystems - with each subsystem consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus - are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe plant operation and to ensure that:

(continued)

BASES

APPLICABILITY (continued)

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

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

The DC electrical power requirements for MODES 4 and 5 and other specified conditions in which the DC electrical power sources are required are addressed in LCO 3.8.5, "DC Sources-Shutdown."

ACTIONS

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

Condition A represents one division of the 125 VDC Power System with one battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability. A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is

(continued)

BASES

ACTIONS

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

indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours, that is an indication that the battery is partially discharged and its capability margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to 2 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 2 amps, this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1

Condition B represents one division of the 125 VDC Power System with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for complete loss of 125 VDC power to the affected division. The 8 hour limit is consistent with the allowed time for an inoperable DC Distribution System division.

If one of the required 125 VDC power subsystems is inoperable for reasons other than Condition A (e.g., inoperable battery, or inoperable battery charger and associated inoperable battery), the remaining 125 VDC power subsystem has the capacity to support a safe shutdown and to mitigate an

(continued)

BASES

ACTIONS

B.1 (continued)

accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary 125 VDC power subsystems to mitigate a worst case accident, continued power operation should not exceed 8 hours. The 8 hour Completion Time reflects a reasonable time to assess plant status as a function of the inoperable 125 VDC power subsystem and, if the 125 VDC power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe plant shutdown.

C.1 and C.2

If the inoperable 125 VDC power subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the plant to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 8).

D.1

If one or both 419 VDC LPCI MOV independent power supply subsystems are inoperable (e.g., inoperable battery, inoperable battery charger, or inoperable battery charger and associated inoperable battery), the associated LPCI subsystem may be incapable of performing its intended function and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions for an inoperable LPCI subsystem, LCO 3.5.1.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the connected loads and the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state, while supplying the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.17 Vpc or 130.2 V at the 125 VDC battery terminals or 403.6 V for 419 VDC LPCI MOV independent power supply battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The Surveillance Frequency is controlled under Surveillance Frequency Control Program.

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers (Ref. 3). According to UFSAR, Section 8.7 (Ref. 4), the battery charger is sized to restore the battery after discharging through its duty cycle to the fully charged state, while supplying the normal control loads. The minimum required amperes and duration ensures that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 270 amps at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ 2 amps.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.3

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements (Ref. 10, 11, and 12).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A modified performance discharge test may be performed in lieu of a service test. This substitution is acceptable because a modified performance discharge test represents a more severe test of battery capacity than the service test.

The modified performance discharge test is a complete test which envelopes both the service test and the performance discharge test requirements. The modified performance discharge test discharge current envelopes the peak duty cycle loads of the service test followed by a constant discharge current (temperature corrected) for the performance discharge test. Since the ampere-hours removed by peak duty cycle loads represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The purpose of the modified performance discharge test is to demonstrate the battery has sufficient capacity to meet the system design requirements and to provide trendable performance data to compare the available capacity in the battery to previous capacity test results. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required 125 VDC power subsystem from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, or 3 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, or 3. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.4

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.4 (continued)

A battery modified performance discharge test is described in the Bases for SR 3.8.4.3. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.4; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.4 while satisfying the requirements of SR 3.8.4.3 at the same time.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 9). This reference recommends that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 9), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is below 90% of the manufacturer's rating. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 9).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required 125 VDC power subsystem from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, or 3 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.4 (continued)

offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, or 3. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. UFSAR, Section 16.6.
2. Safety Guide 6, Independence Between Redundant Standby (Onsite) Power Sources And Between Their Distribution Systems, March 1971.
3. IEEE Standard 308, IEEE Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations, 1971.
4. UFSAR, Section 8.7.
5. UFSAR, Chapter 6.
6. UFSAR, Chapter 14.
7. 10 CFR 50.36 (c) (2) (ii).
8. Regulatory Guide 1.93, Availability Of Electric Power Sources, December 1974.
9. IEEE Standard 450, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead - Acid Batteries for Stationary Applications, 1995.
10. JAF-CALC-ELEC-02609
11. JAF-CALC-ELEC-02610
12. JAF-CALC-ELEC-01857

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSIS

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 14 (Ref. 2), assume that Engineered Safeguards systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the emergency diesel generators (EDGs), emergency auxiliaries, and control and switching during all MODES of operation and during movement of recently irradiated fuel assemblies in the secondary containment.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the plant status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a refueling accident involving handling recently irradiated fuel. Due to radioactive decay, DC electrical power is only required to mitigate fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

In general, when the unit is shutdown, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case Design Basis Accidents which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

LCO

One 125 VDC electrical power subsystem consisting of one 125 V battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus is required to be OPERABLE to support one DC distribution subsystem required OPERABLE by LCO 3.8.8, "Distribution Systems—Shutdown." This requirement ensures the availability of sufficient DC electrical power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., refueling accidents involving handling recently irradiated fuel).

(continued)

BASES (continued)

APPLICABILITY

The DC electrical power sources required to be OPERABLE inMODES 4 and 5 and during movement of recently irradiated fuel assemblies in the secondary containment provide assurance that:

a. Required features to provide core cooling are available;

b. Required features needed to mitigate a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours) are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since recently irradiated fuel assembly movement can occur in MODE 1, 2 or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, or 3 would require the unit to be shutdown unnecessarily.

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

By allowance of the option to declare required features inoperable with the associated DC electrical power subsystem inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. These required features are those that are assumed in the safety analysis to function to mitigate events postulated during shutdown, such as a fuel handling accident involving recently irradiated fuel. These required features do not include monitoring requirements. However, in many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies in the secondary containment). Suspension of these

(continued)

BASES

ACTIONS

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

activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystem and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.4. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC electrical power subsystem from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 14.
3. 10 CFR 50.36(c)(2)(ii).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND	This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC electrical power subsystems batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources – Operating," and LCO 3.8.5, "DC Sources – Shutdown."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 6 (Ref. 1) and Chapter 14 (Ref. 2), assume Engineered Safeguards systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the emergency diesel generators (EDGs), emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant as discussed in the Bases for LCO 3.8.4 and LCO 3.8.5. Since battery cell parameters support the operation of the DC electrical power subsystems, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).
LCO	Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, these battery cell parameters are only required when the associated DC electrical power subsystem is required to be OPERABLE. Refer to the Applicability discussions in Bases for LCO 3.8.4 and LCO 3.8.5.

(continued)

BASES (continued)

ACTIONS

The ACTIONS Table is modified by a Note which indicates that separate Condition entry is allowed for each battery. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DC subsystem. Complying with the Required Actions for one inoperable DC subsystem may allow for continued operation, and subsequent inoperable DC subsystems are governed by separate Condition entry and application of associated Required Actions.

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

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met or Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell(s) electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cell(s). One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A and B limits. This periodic verification is consistent with the guidance provided in IEEE-450 (Ref. 4) of monitoring battery conditions at regular intervals (not to exceed one week) while completing corrective actions.

(continued)

BASES

ACTIONS

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

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. Taking into consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable for operation prior to declaring the DC batteries inoperable.

B.1

When any battery parameter is outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not ensured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potential conditions, such as any Required Action of Condition A and associated Completion Time not met, or average electrolyte temperature of representative cells < 65°F for each 125 VDC battery, or < 50°F for each 419 VDC LPCI MOV independent power supply battery, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 4), which recommends regular battery inspections including voltage, specific gravity, and electrolyte temperature of pilot cells. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.2

The inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 4), which recommends augmentation of the battery inspections conducted in SR 3.8.6.1 by checking voltage, specific gravity and electrolyte temperature. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3

This Surveillance verification that the average electrolyte temperature of representative cells (10% of total) is within limits is consistent with a recommendation of IEEE-450 (Ref. 4). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Lower than normal electrolyte temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range, based on assumptions in the battery sizing analyses.

Table 3.8.6-1

This Table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 4), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperature and charge effects. In addition to this allowance, footnote (a) to Table 3.8.6-1 permits the electrolyte level to be temporarily above the specified maximum level during and, for a limited time, following an equalizing charge (normally up to 3 days following the completion of an equalization charge to allow electrolyte stabilization), provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 4) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

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BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendation of IEEE-450 (Ref. 4), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells.
The Category A limit specified for specific gravity for each pilot cell is ≥ 1.195 (0.020 below the manufacturer's fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 4), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturer's recommendations.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells 1.205 (0.010 below the manufacturer's fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limit for voltage is based on IEEE-450 Appendix C (Ref. 4), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit on average specific gravity ≥ 1.195, is based on manufacturer's recommendations (0.020 below the manufacturer's recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote (b) of Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current, while on float charge, is < 2 amps for 125 VDC batteries and < 1.0 amp for 419 VDC LPCI MOV independent power supply batteries. This current provides, in general, an indication of acceptable overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charging current is an acceptable alternative to specific gravity measurement for determining the state of charge of the designated pilot cell. This phenomenon is discussed in IEEE-450 (Ref. 4). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within 7 days, each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 14.

3. 10 CFR 50.36(c)(2)(ii).

4. IEEE Standard 450, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications, 1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems - Operating

BASES

BACKGROUND

The plant Class IE AC and 125 VDC electrical power distribution system is divided into redundant and independent AC, and 125 VDC electrical power distribution subsystems.

The primary AC distribution system consists of two 4.16 kV emergency buses each having an offsite source of power as well as a dedicated onsite emergency diesel generator (EDG) source. Each 4.16 kV emergency bus is normally connected to the normal station service transformer (71T-4). During a loss of the normal power source to the 4.16 kV emergency buses, each emergency bus will be automatically transferred to its associated reserve station service transformer (71T-2 or 71T-3). The normal and reserve sources feed their associated 4.16 kV emergency bus via a non-emergency bus and the associated breakers. If both normal and reserve sources are unavailable, the onsite EDGs supply power to the 4.16 kV emergency buses.

The secondary plant distribution system includes 600 VAC emergency buses, and associated load centers, and transformers.

There are two independent 125 VDC electrical power distribution subsystems that support the necessary power for engineered safeguards functions.

The list of required distribution buses is presented in Table B 3.8.7-1.

APPLICABLE SAFETY ANALYSIS

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 14 (Ref. 2), assume engineered safeguards systems are OPERABLE. The AC and 125 VDC electrical power distribution subsystems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to Engineered Safeguards systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6 Containment Systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The OPERABILITY of the AC, and 125 VDC electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all reserve power or all onsite AC electrical power; and

b. A worst case single active component failure.

The AC and 125 VDC electrical power distribution subsystems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

LCO

The required electrical power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC, and 125 VDC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. The AC and 125 VDC electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Division 1 and Division 2 AC and 125 VDC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of Engineered Safeguards systems is not defeated. Therefore, a single active component failure within any system or a single failure within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses and electrical circuits to be energized to their proper voltages. OPERABLE 125 VDC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger.

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.7-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Other buses, such as motor control centers (MCC) and distribution panels, which help comprise the AC and 125 VDC distribution systems are not listed in Table B 3.8.7-1. The loss of electrical loads associated with these buses may not result in a complete loss of redundant safety function necessary to shut down the reactor and maintain it in a safe condition.

Therefore, should one or more of these buses become inoperable due to failure not affecting the OPERABILITY of a bus listed in

(continued)

BASES

LCO (continued)

Table B 3.8.7-1 (e.g., a breaker supplying a single MCC fails open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.7-1 (e.g., loss of a 4.16 kV emergency bus, which results in deenergization of all buses powered from the 4.16 kV emergency bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV emergency bus).

In addition, tie breakers between redundant safety related AC, and 125 VDC power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers between redundant safety related AC or 125 VDC power distribution subsystems are closed, the electrical power distribution subsystem that is not being powered from its normal source (i.e., it is being powered from its redundant electrical power distribution subsystem) is considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems.

APLLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

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

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

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC and 125 VDC electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.8, "Distribution Systems - Shutdown."

(continued)

BASES (continued)

ACTIONS

A.1

With one or more required AC electrical power distribution subsystems inoperable and a loss of function has not occurred. the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition. assuming no single failure. The overall reliability is reduced. however. because a single failure in the remaining power distribution subsystems could result in the minimum required engineered safeguards functions not being supported. Therefore, the required AC electrical power distribution subsystems must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no reserve or normal power to the division and the associated EDG subsystem inoperable). In this Condition, the plant is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the plant operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the plant. and on restoring power to the affected division. The 8 hour time limit before requiring a plant shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the plant operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the plant to shutdown within this time limit.

b. The low potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.12, "Safety Function Determination Program (SFDP).")

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time this LCO was initially not met, instead of at the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

(continued)

BASES

ACTIONS (continued)

B.1

With one 125 VDC electrical power distribution subsystems inoperable, the remaining 125 VDC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining 125 VDC electrical power distribution subsystem could result in the minimum required engineered safeguards functions not being supported. Therefore, the required 125 VDC electrical power distribution subsystem must be restored to OPERABLE status within 8 hours by powering the bus from the associated battery or charger.

Condition B represents one division without adequate 125 VDC power, potentially with both a battery significantly degraded and the associated charger nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all 125 VDC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining divisions, and restoring power to the affected division.

This 8 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate 125 VDC power, which would have Required Action Completion Times shorter than 8 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without 125 VDC power, while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division;

c. The potential for an event in conjunction with a single failure of a redundant component.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable distribution subsystem 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.

D.1

Condition D corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost. When more than one AC or 125 VDC electrical power distribution subsystem is lost, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and 125 VDC, electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical buses are maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 14.
3. 10 CFR 50.36(c)(2)(ii).

Table B 3.8.7-1 (page 1 of 1)
AC and 125 VDC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1*	DIVISION 2*
AC safety buses	4160 V 600 V	Emergency Bus 10500 Load Centers 11500, 12500	Emergency Bus 10600 Load Centers 11600, 12600
125 VDC buses	125 VDC	Bus 71BCB-2A	Bus 71BCB-2B

* Each division of the AC and 125 VDC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of the AC and 125 VDC electrical power distribution system is provided in the Bases for LCO 3.8.7, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSIS

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 14 (Ref. 2), assume Engineered Safeguards systems are OPERABLE. The AC and 125 VDC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to Engineered Safeguards systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC and 125 VDC electrical power distribution systems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and 125 VDC electrical power sources and associated power distribution subsystems during MODES 4 and 5, and during movement of recently irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the plant status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, AC and DC electrical power is only required to mitigate fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours).

The AC and 125 VDC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of Technical Specification required systems, equipment, and components—both specifically addressed by their own LCO, and implicitly required by the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling recently irradiated fuel).

APPLICABILITY

The AC and 125 VDC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems that provide core cooling are available;

b. Systems needed to mitigate a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 96 hours) are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition or refueling condition.

The AC, and 125 VDC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since recently irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3,

(continued)

BASES

ACTIONS (continued)

the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, or 3 would require the unit to be shutdown unnecessarily.

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

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, recently irradiated fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. These required features are those that are assumed in the safety analysis to function to mitigate events postulated during shutdown, such a fuel handling accident involving recently irradiated fuel. These required features do not include monitoring requirements. In many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made, (i.e., to suspend CORE ALTERATIONS and movement of recently irradiated fuel assemblies in the secondary containment).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and 125 VDC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

Not withstanding performance of the above conservative Required Actions, a required residual heat removal-shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and 125 VDC electrical power distribution subsystems are functioning properly, with the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 14.
3. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to reinforce plant procedures that prevent the reactor from achieving criticality during refueling. The refueling interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

UFSAR, Section 16.6, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

Two channels of instrumentation are provided to sense the full insertion of all control rods. One channel of instrumentation is provided to sense the position of the refueling platform, the loading of the refueling platform fuel grapple, the loading of the refueling platform frame mounted hoist, the loading of the refueling platform trolley mounted (monorail) hoist, and the fuel grapple in the not fully up position. With the reactor mode switch in the shutdown or refueling position, the indicated conditions are combined in logic circuits to establish appropriate restrictions on refueling equipment operations and control rod movement.

A control rod not at its full-in position disables the control circuitry permissive to the refueling equipment to prevent operating the equipment near or over the reactor core when loaded with a fuel assembly or if the fuel grapple is not fully up. Conversely, with the refueling platform near or over the core and loaded with fuel or the fuel grapple is not fully up a control rod withdrawal block is inserted in the Reactor Manual Control System to prevent withdrawing a control rod.

The refueling platform has two mechanical switches that open before the platform or any of its hoists are physically located over the reactor vessel. However, only one of these switches provides input to the required refueling interlock

(continued)

BASES

BACKGROUND (continued)

circuitry with the reactor mode switch in the refuel position. Each control rod full-in position channel provides input to two all-rods-in channels. Both all-rods-in channels must register for the refueling interlock circuitry to indicate the all-rods-in condition. All refueling hoists have switches that open when the hoists are loaded with fuel. The hoist switches open at a load lighter than the weight of a single fuel assembly in water. In addition, a switch will open if the fuel grapple is not fully up.

The refueling interlocks use these indications to prevent operation of the refueling equipment near or over the core with fuel loaded or the fuel grapple not fully up whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever the refueling equipment is near or over the core and loaded with fuel or the fuel grapple is not fully up (Ref. 2).

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the UFSAR analyses for the control rod withdrawal error during refueling (Ref. 3) and the fuel assembly insertion error during refueling (Ref. 4). These analyses evaluate the consequences of control rod withdrawal during refueling and also fuel assembly insertion with a control rod withdrawn. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading of fuel into the core with any control rod withdrawn or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point outside of the reactor core such that, with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling equipment interlocks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii)(Ref.5).

(continued)

BASES (continued)

LCO

To prevent criticality during refueling, the refueling equipment interlocks associated with the reactor mode switch in the refuel position ensure that fuel assemblies are not loaded into the core with any control rod withdrawn.

To prevent these conditions from developing, the all-rods-in, the refueling platform position, the refueling platform fuel grapple fuel loaded, the refueling platform trolley mounted (monorail) hoist fuel loaded, the refueling platform frame mounted hoist fuel loaded, and the refueling platform fuel grapple not full up position inputs are required to be OPERABLE. These inputs are combined in logic circuits, which provide refueling equipment control circuitry permissive interruptions or control rod blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks when the reactor mode switch is in the refuel position. The interlocks are not required when the reactor mode switch is in the shutdown position because a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawal cannot occur simultaneously with in-vessel fuel movements.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and fuel loading activities are not possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

ACTIONS

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

With one or more of the required refueling equipment interlocks inoperable, the plant must be placed in a condition in which the LCO does not apply or the Surveillances are not needed. This can be performed by ensuring fuel assemblies are not moved in the reactor vessel or by ensuring that the control rods are inserted and cannot be withdrawn. Therefore, Required Action A.1 requires that in-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment

(continued)

BASES

ACTIONS

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

that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

Alternately, Required Actions A.2.1 and A.2.2 require that a control rod withdrawal block be inserted and that all control rods are subsequently verified to be fully inserted. Required Action A.2.1 ensures that no control rods can be withdrawn. This action ensures that control rods cannot be inappropriately withdrawn because an electrical or hydraulic block to control rod withdrawal is in place. Required Action A.2.2 is performed after placing the rod withdrawal block in effect. This verification that all control rods are fully inserted is in addition to the periodic verifications required by SR 3.9.3.1 and SR 3.10.6.2. Like Required Action A.1, Required Actions A.2.1 and A.2.2 ensure that unacceptable operations are blocked (e.g., loading fuel into a cell with the control rod withdrawn).

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 7.6.3.
3. UFSAR, Section 14.5.4.3.
4. UFSAR, Section 14.5.4.4.
5. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position One-Rod-Out Interlock

BASES

BACKGROUND

The refuel position one-rod-out interlock restricts the movement of control rods to reinforce plant procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn except as allowed by LCO 3.10.6, "Multiple Control Rod Withdrawal – Refueling".

UFSAR, Section 16.6, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refuel position one-rod-out interlock prevents the selection of a second control rod for movement when any other control rod is not fully inserted (Ref. 2). It is a logic circuit that has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the Reactor Manual Control System).

This Specification ensures that the performance of the refuel position one-rod-out interlock in the event of a Design Basis Accident meets the assumptions used in the safety analysis of Reference 3.

APPLICABLE SAFETY ANALYSES

The refueling position one-rod-out interlock is explicitly assumed in the UFSAR analysis for the control rod withdrawal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

The refuel position one-rod-out interlock and adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), prevent criticality. The interlock prevents withdrawal of more than one control rod and adequate SDM ensures that the core will remain subcritical with the highest worth control rod fully withdrawn, thereby preventing any prompt critical excursion.

The refuel position one-rod-out interlock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

(continued)

BASES (continued)

LCO

To prevent criticality during MODE 5, the refuel position one-rod-out interlock ensures no more than one control rod may be withdrawn. Both channels of the refuel position one-rod-out interlock are required to be OPERABLE and the reactor mode switch must be locked in the refuel position to support the OPERABILITY of these channels.

APPLICABILITY

In MODE 5, with the reactor mode switch in the refuel position, the OPERABLE refuel position one-rod-out interlock provides protection against prompt reactivity excursions.

In MODES 1, 2, 3, and 4, the refuel position one-rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") and the control rods (LCO 3.1.3, "Control Rod OPERABILITY") provide mitigation of potential reactivity excursions. In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

A.1 and A.2

With one or both channels of the refueling position one-rod-out interlock inoperable, the refueling interlocks may not be capable of preventing more than one control rod from being withdrawn. This condition may lead to criticality.

Control rod withdrawal must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

Proper functioning of the refueling position one-rod-out interlock requires the reactor mode switch to be in the refuel position. During control rod withdrawal in MODE 5, improper positioning of the reactor mode switch could, in some instances, allow improper bypassing of required

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1 (continued)

interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refueling position one-rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the console while the reactor mode switch is positioned in refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.

REFERENCES

1. UFSAR, Section 16.6.

2. UFSAR, Section 7.6.3.

(continued)

BASES

REFERENCES (continued)

3. UFSAR, Section 14.5.4.3.

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

B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND

Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Reactor Manual Control System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") or the control rod block with the reactor mode switch in the shutdown position (LCO 3.3.2.1, "Control Rod Block Instrumentation").

UFSAR, Section 16.6, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refueling interlocks allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. To preclude loading fuel assemblies into the core with a control rod withdrawn, all control rods must be fully inserted (Ref. 2), except as allowed by LCO 3.10.6, "Multiple Control Rod Withdrawal – Refueling". This precludes criticality during refueling operations.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis for the control rod removal error during refueling in the UFSAR (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The analysis for the fuel assembly insertion error (Ref. 3) assumes all control rods are fully inserted. Thus, prior to fuel reload, all control rods must be fully inserted to minimize the probability of an inadvertent criticality.

Control rod position satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

(continued)

BASES (continued)

LCO

All control rods must be fully inserted during applicable refueling conditions to minimize the probability of an inadvertent criticality during refueling.

APPLICABILITY

During MODE 5, loading fuel into core cells with control rods withdrawn may result in inadvertent criticality. Therefore, the control rods must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, this Specification is not applicable in these MODES.

ACTIONS

A.1

With all control rods not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed in the UFSAR. All fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 14.5.4.3.
3. UFSAR, Section 14.5.4.4.
4. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication channel (i.e., the full-in switch providing the green full-in light) for each control rod provides necessary information to the refueling interlocks to prevent inadvertent criticalities during refueling operations. During refueling, the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") use the full-in position indication channel to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full-in position channel signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this condition causes the refuel position one-rod-out interlock to not allow the withdrawal of any other control rod.

UFSAR, Section 16.6, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analysis for the control rod withdrawal error during refueling (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The analysis for the fuel assembly insertion error (Ref. 3) assumes all control rods are fully inserted. The full-in position indication channel is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod withdrawn and that no more than one control rod can be withdrawn at a time.

Control rod position indication satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

(continued)

BASES (continued)

LCO

Each control rod full-in position indication channel must be OPERABLE to provide the required input to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling interlock logic.

APPLICABILITY

During MODE 5, the control rods must have OPERABLE full-in position indication channels to ensure the applicable refueling interlocks will be OPERABLE.

In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

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

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2

With one or more full-in position indication channels inoperable, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by immediately suspending in-vessel fuel movement and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and,

(continued)

BASES

ACTIONS

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2 (continued)

therefore, do not have to be inserted. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude moving a component to a safe position.

Alternatively, actions must be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicator(s) and disarm (electrically or hydraulically) the drive(s) to ensure that the control rod is not withdrawn. A control rod can be hydraulically disarmed by closing the drive water and exhaust water valves. A control rod can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Actions must continue until all associated control rods are fully inserted and drives are disarmed. Under these conditions (control rod fully inserted and disarmed), an inoperable full-in channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication).

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels provide input to the one-rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are actuated when the full-in position indication for any control rod is not present, since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indication channels is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. Note that failure to indicate full-in when the control rod is not withdrawn results in conservative actuation of the one-rod-out interlock, and therefore, is not explicitly required to be verified by this SR. The full-in position indication channel is considered inoperable even with the control rod fully inserted, if it would continue to indicate full-in with the control rod withdrawn. Performing the SR each time a control rod is withdrawn is considered adequate because of the procedural controls on control rod withdrawals and the visual indications and alarms available in the control room to alert the operator to control rods not fully inserted.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 14.5.4.3.
3. UFSAR, Section 14.5.4.4.
4. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY – Refueling

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operation. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System.

UFSAR, Section 16.6, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The CRD System is the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analyses for the control rod withdrawal error during refueling (Ref. 2) and the fuel assembly insertion error (Ref. 3) evaluate the consequences of control rod withdrawal during refueling and also fuel assembly insertion with a control rod withdrawn. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides protection should a prompt reactivity excursion occur.

Control rod OPERABILITY during refueling satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator pressure is ≥ 940 psig and the control rod is capable of

(continued)

BASES

LCO (continued)

being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function, and therefore are not required to be OPERABLE.

APPLICABILITY

During MODE 5, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical.

For MODES 1 and 2, control rod requirements are found in LCO 3.1.2, "Reactivity Anomalies," LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." During MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions.

ACTIONS

A.1

With one or more withdrawn control rods inoperable, action must be immediately initiated to fully insert the inoperable control rod(s). Inserting the control rod(s) ensures the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable control rod(s) is fully inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2

During MODE 5, the OPERABILITY of control rods is primarily required to ensure a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit analysis exists for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated CRD scram accumulator pressure is ≥ 940 psig.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2 (continued)

SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance, and therefore avoids potential conflicts with SR 3.0.3 and SR 3.0.4.

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 14.5.4.3.
3. UFSAR, Section 14.5.4.4.
4. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND

The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 22 ft 2 inches above the top of the RPV flange. During refueling, this maintains a sufficient water level in the reactor vessel cavity. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a refueling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to ≤ 25% of 10 CFR 100 (Ref. 3) limits, as provided by the guidance of Reference 4.

APPLICABLE SAFETY ANALYSES

During movement of fuel assemblies or handling of control rods, the water level in the RPV is an initial condition in the analysis of a refueling accident postulated by Reference 1. A minimum water level of 22 ft 2 inches above the top of the RPV flange allows a decontamination factor of 100 to be used in the accident analysis for iodine since more than 23 feet of water is available over the top of the reactor core (Ref. 1). This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all damaged fuel assembly rods is retained by the water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1).

Analysis of the refueling accident inside containment is described in Reference 2. With a minimum water level of 22 ft 2 inches above the top of the RPV flange and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated refueling accident is adequately captured by the water and that offsite doses are maintained within allowable limits (Ref. 3). While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core loaded with irradiated fuel, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure acceptable radiological consequences is specified from the RPV flange. Since the worst case event results in failed fuel assemblies seated in the core, as well as the dropped assembly, dropping an assembly on the RPV flange will result in

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	reduced releases of fission gases. Based on analysis of the physical dimensions which preclude normal operation with water level 23 feet above the flange, this water level is acceptable. RPV water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).
LCO	A minimum water level of 22 ft 2 inches above the top of the RPV flange is required to ensure that the radiological consequences of a postulated refueling accident are within acceptable limits, as provided by the guidance of Reference 4.
APPLICABILITY	LCO 3.9.6 is applicable when moving fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) within the RPV. The LCO minimizes the possibility of a refueling accident that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated refueling accident. Requirements for fuel movement in the spent fuel storage pool are covered by LCO 3.7.7, "Spent Fuel Storage Pool Water Level."
ACTIONS	A.1 If the water level is < 22 ft 2 inches above the top of the RPV flange, all operations involving movement of fuel assemblies and handling of control rods within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	SR 3.9.6.1 Verification of a minimum water level of 22 ft 2 inches above the top of the RPV flange ensures that the design basis for the postulated refueling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a refueling accident in containment (Ref. 2).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Regulatory Guide 1.25, Assumptions Used for Evaluating The Potential Radiological Consequences Of A Fuel Handling Accident In The Fuel Handling And Storage Facility For Boiling And Pressurized Water Reactors, March 23, 1972.

2. UFSAR, Section 14.6.1.4.

3. 10 CFR 100.11.

4. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 15.7.4, Revision 1, Radiological Consequences of Fuel Handling Accident, July 1981.

5. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.7 Residual Heat Removal (RHR) – High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by the UFSAR (Ref. 1). Either of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

In addition to the RHR shutdown cooling mode, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the plant in MODE 5, the RHR shutdown cooling mode is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR shutdown cooling mode is required for removing decay heat to maintain the temperature of the reactor coolant.

The RHR shutdown cooling mode satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and the water level ≥ 22 ft 2 inches above the top of the RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, an RHR service water pump capable of providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In MODE 5, the RHR cross tie valves are not required to be closed; thus, the valves may be opened to allow pumps in one loop to discharge through the opposite recirculation loop to make a complete subsystem.

(continued)

BASES

LCO (continued)

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (from the control room or locally) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required.

APPLICABILITY

One RHR shutdown cooling subsystem must be OPERABLE in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level ≥ 22 ft 2 inches above the top of the RPV flange, to provide decay heat removal. RHR shutdown cooling subsystem requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR shutdown cooling subsystem requirements in MODE 5 with irradiated fuel in the reactor pressure vessel and with the water level < 22 ft 2 inches above the top of the RPV flange are given in LCO 3.9.8, "Residual Heat Removal (RHR) – Low Water Level".

ACTIONS

A.1

With no RHR shutdown cooling subsystem OPERABLE, an alternate method of decay heat removal must be established within 1 hour. In this condition, the volume of water above the top of the RPV flange provides adequate capability to remove decay heat from the reactor core. However, the overall reliability is reduced because loss of water level could result in reduced decay heat removal capability. The 1 hour Completion Time is based on decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of the alternate method must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the plant Operating Procedures. The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. For example, this may include the use of the Spent Fuel Pool Cooling System and the Reactor Water Cleanup System, operating with the regenerative heat exchanger bypassed or in combination with the Control Rod Drive System or Condensate System. In addition, the Decay Heat Removal

(continued)

BASES

ACTIONS

A.1 (continued)

System can also be used as a method. The method used to remove the decay heat should be the most prudent choice based on plant conditions. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability.

B.1, B.2, B.3, and B.4

If no RHR shutdown cooling subsystem is OPERABLE and an alternate method of decay heat removal is not available in accordance with Required Action A.1, actions shall be taken immediately to suspend operations involving an increase in reactor decay heat load by suspending loading of irradiated fuel assemblies into the RPV.

Additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flowpath not isolated that is assumed to be isolated to mitigate radioactive releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or acceptable administrative controls assure isolation capability. These administrative controls consist of stationing an operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment is indicated). This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR shutdown cooling flow path provides assurance that the proper flow paths will exist for RHR operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that can be manually (from the control room or locally) aligned is allowed to be in a non-RHR shutdown cooling position provided the valve can be repositioned. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 16.6.

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

B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR) – Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by the UFSAR (Ref. 1). Either of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSES

With the plant in MODE 5, the RHR shutdown cooling mode is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR shutdown cooling mode is required for removing decay heat to maintain the temperature of the reactor coolant.

The RHR shutdown cooling mode satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and the water level < 22 ft 2 inches above the top of the reactor pressure vessel (RPV) flange two RHR shutdown cooling subsystems must be OPERABLE.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, an RHR service water pump capable of providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. To meet the LCO, two RHR pumps and two RHR service water pumps in one loop or one RHR pump and one RHR service water pump in each of the two loops must be OPERABLE. In MODE 5, the RHR cross tie valves are not required to be closed; thus, the valves may be opened to allow pumps in one loop to discharge through the opposite recirculation loop to make a complete subsystem.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (from the control room or locally) in the shutdown cooling mode for

(continued)

BASES

LCO (continued)

removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required.

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE in MODE 5, with irradiated fuel in the RPV and with the water level < 22 ft 2 inches above the top of the RPV flange, to provide decay heat removal. RHR shutdown cooling subsystem requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR shutdown cooling subsystem requirements in MODE 5 with irradiated fuel in the RPV and with the water level ≥ 22 ft 2 inches above the top of the RPV flange are given in LCO 3.9.7, "Residual Heat Removal (RHR) – High Water Level."

ACTIONS

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both required RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of this alternate method must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the plant Operating Procedures. The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capacity to maintain or reduce temperature. For example, this may include the use of the Spent Fuel Pool Cooling System and the Reactor Water Cleanup System, operating with the regenerative heat exchanger bypassed or in combination with the Control Rod Drive System

(continued)

BASES

ACTIONS

A.1 (continued)

or Condensate System. The method used to remove decay heat should be the most prudent choice based on plant conditions. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability.

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

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Required Action A.1, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactive releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or acceptable administrative controls assure isolation capability. These administrative controls consist of stationing an operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment is indicated). This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR shutdown cooling flow paths provides assurance that the proper flow paths will exist for RHR operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1 (continued)

locking, sealing, or securing. A valve that can be manually (from the control room or locally) aligned is allowed to be in a non-RHR shutdown cooling position provided the valve can be repositioned. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 16.6.

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

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 212°F (normally corresponding to MODE 3).

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation, decay heat and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (PIT) limits required by LCO 3.4.9, "Reactor Coolant System (RCS) Pressure and Temperature (PIT) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RCS PIT limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel.

APPLICABLE SAFETY ANALYSIS

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing, when the reactor coolant temperature is > 212°F, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems. Since the hydrostatic or leak tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the LCO 3.4.6, "RCS Specific Activity," limits are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a recirculation line break (Refs. 2 and 3) will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in Reference 4. Therefore, these requirements will conservatively limit radiation releases to the environment.

In the unlikely event of any primary system leak that could result in draining of the RPV, the reactor vessel would rapidly depressurize. The makeup capability required in MODE 4 by LCO 3.5.2. "Reactor Pressure Vessel (RPV) Water Inventory Control," would be more than adequate to keep the RPV water level above the TAF under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test. the protection provided by normally required MODE 4 applicable LCOs, in addition to the secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 5) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures> 212°F can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures > 212°F, while performance of inservice leak and hydrostatic testing results in inoperability of subsystems required when > 212°F.

If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.8, "Residual Heat Removal

(continued)

BASES

LCO (continued)

(RHR) Shutdown Cooling System-Cold Shutdown." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 212°F for the purpose of performing either an inservice leak or hydrostatic test.

This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements that are in effect immediately prior to and immediately after this operation.

APPLICABILITY

The MODE 4 requirements may only be modified for the performance of inservice leak or hydrostatic tests so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is > 212°F. The additional requirement for secondary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the plant to any event that may occur. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements are entered immediately and complied with. Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in MODE 4 includes reducing the average reactor coolant temperature to ≤ 212°F.

(continued)

BASES

ACTIONS (continued)

A.2.1 and A.2.2

Required Action A.2.1 and Required Action A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, and thereby exit this Special Operation LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the reactor coolant temperature is reduced to establish normal MODE 4 requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest expected value to ≤ 212°F with normal cooldown procedures. The Completion Time is also consistent with the time provided in LCO 3.0.3 to reach MODE 4 from MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1

The LCOs made applicable are required to have their Surveillances met to establish that this LCO is being met. A discussion of the applicable SRs is provided in their respective Bases.

REFERENCES

1. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI.
2. JAF-CALC-MULT-02238, Revision I, JAF-HELB Analysis During Hydrostatic Test, May 27, 1999.
3. JAF-CALC-RBC-03400, Revision 0, Evaluation of Reactor Building Ducts and Doors for Recirc. Break During Hydro, August 9, 1999.
4. UFSAR. Section 14.6.1.5.
5. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip relays for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

a. Shutdown – Initiates a reactor scram; bypasses main steam line isolation scrams;

b. Refuel – Selects Reactor Protection System (RPS) Neutron Monitoring System (NMS) scram function for low neutron flux level operation (but does not disable the average power range monitor scram); bypasses main steam line isolation;

c. Startup/Hot Standby – Selects RPS NMS scram function for low neutron flux level operation (intermediate range monitors and average power range monitors); bypasses main steam line isolation scram; and

d. Run – Selects RPS NMS scram function for power range operation.

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram discharge volume trip bypass, refueling equipment interlocks, and main steam isolation valve isolations.

APPLICABLE SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality. The interlock functions of the shutdown and refuel positions normally maintained for the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (run, startup/hot

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

standby, or refuel) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no CORE ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies, and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

For postulated accidents, such as control rod withdrawal error during refueling or loading of fuel with a control rod withdrawn, the accident analysis demonstrates that fuel failure will not occur (Refs. 2 and 3). The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 4) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation," LCO 3.10.3, "Single Control Rod Withdrawal – Hot Shutdown," LCO 3.10.4, "Single Control Rod Withdrawal – Cold Shutdown," and LCO 3.10.8, "SDM Test – Refueling") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, the testing can be performed, provided all interlock functions potentially defeated are administratively controlled. In MODES 3, 4, and 5 with the reactor mode switch in shutdown as specified in Table 1.1-1, all control rods are fully inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified fully inserted while in MODES 3, 4, and 5, with the reactor mode switch in other than the shutdown position. The additional LCO requirement to preclude CORE ALTERATIONS is

(continued)

BASES

LCO (continued)

appropriate for MODE 5 operations, as discussed below, and is inherently met in MODES 3 and 4 by the definition of CORE ALTERATIONS, which cannot be performed with the vessel head in place.

In MODE 5, with the reactor mode switch in the refuel position, only one control rod can be withdrawn under the refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS. Due to the increased potential for error in controlling these multiple interlocks, and the limited duration of tests involving the reactor mode switch position, conservative controls are required, consistent with MODES 3 and 4. The additional controls of administratively not permitting CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.

APPLICABILITY

Any required periodic interlock testing involving the reactor mode switch, while in MODES 1 and 2, can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in plant trips. In MODES 3, 4, and 5, this Special Operations LCO allows reactor mode switch interlock testing that cannot conveniently be performed without this allowance or testing that must be performed prior to entering another MODE. Such interlock testing may consist of required Surveillances, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, and 5, the interlock functions provided by the reactor mode switch in shutdown (i.e., all control rods inserted and incapable of withdrawal) and refueling (i.e., refueling interlocks to prevent inadvertent criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Restoring compliance will also result in exiting the Applicability of this Special Operations LCO.

(continued)

BASES

ACTIONS

A.1, A.2, A.3.1, and A.3.2 (continued)

All CORE ALTERATIONS, except control rod insertion, if in progress, are immediately suspended in accordance with Required Action A.1, and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted within 1 hour, in accordance with Required Action A.2. This will preclude potential mechanisms that could lead to criticality. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Placing the reactor mode switch in the shutdown position will ensure that all inserted control rods remain inserted and result in operating in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch may be placed in the refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Required Action is only applicable in MODE 5, since only the shutdown position is allowed in MODES 3 and 4. The allowed Completion Time of 1 hour for Required Action A.2, Required Action A.3.1, and Required Action A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position, based on operating experience, and is acceptable given that all operations that could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the shutdown position (or the refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 7.2.
2. UFSAR, Section 14.5.4.3.
3. UFSAR, Section 14.5.4.4.
4. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Single Control Rod Withdrawal – Hot Shutdown

BASES

BACKGROUND

The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod for testing while in hot shutdown, by imposing certain restrictions. In MODE 3, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances may arise while in MODE 3 that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. This Special Operations LCO provides the appropriate additional controls to allow a single control rod withdrawal in MODE 3.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 3, these analyses will bound the consequences of a postulated accident. Explicit safety analyses in the UFSAR (Refs. 1 and 2) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling.

Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 3) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 with the reactor mode switch in the refuel position can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.2, "Reactor Mode Switch Interlock Testing," without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod withdrawal is desired in MODE 3, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod can be withdrawn. To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods in the vicinity of the withdrawn control rod are known to be inserted and incapable of withdrawal (Item d.2), the possibility of criticality on withdrawal of this control rod is sufficiently precluded, so as not to require the scram capability of the withdrawn control rod. Also, once this alternate (Item d.2) is completed, the LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.
APPLICABILITY	Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, and if limited to one control rod.

(continued)

BASES

APPLICABILITY (continued)

This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication"), full insertion requirements for all other control rods and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation", and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls in Item d.2 of this Special Operations LCO, preclude unacceptable reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 3. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. Required Action A.1 has been modified by a Note that claries the intent of any other LCO's Required Action, to insert all control rods. This Required Action includes exiting this Special Operations Applicability by returning the reactor mode switch to the shutdown position. A second Note has been added, which clarifies that this Required Action is only applicable if the requirements not met are for an affected LCO.

(continued)

BASES

ACTIONS (continued)

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. The control rods can be hydraulically disarmed by closing the drive water and exhaust header water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. SR 3.10.3.2 has been modified by a Note, which clarifies that this SR is not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod being withdrawn are fully inserted. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.5.4.3.

2. UFSAR, Section 14.5.4.4.

3. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single Control Rod Withdrawal – Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod for testing or maintenance, while in cold shutdown, by imposing certain restrictions. In MODE 4, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the installed interlocks associated with the reactor mode switch in the shutdown position. Circumstances may arise while in MODE 4, however, that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated control rod drive (CRD). These single control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 4, these analyses will bound the consequences of a postulated accident. Explicit safety analyses in the UFSAR (Refs. 1 and 2) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks fail to prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing a CRD because this removal renders the withdrawn control rod incapable of being scrammed.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 3) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 4 with the reactor mode switch in the refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO will ensure that only one control rod can be withdrawn. The requirements of LCO 3.9.4, "Control Rod Position Indication" can continue to be met even when the control rod position indication probe is disconnected to allow de-coupling, provided the withdrawn control rod does not erroneously indicate "full-in." However, in the event the control rod does indicate "full-in" (either due to component malfunction or intentional jumpering to cause a "full-in" indication), a control rod withdrawal block is required to be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained.

To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by the Special Operations LCO requirements in Item c.1. Alternatively, when the scram function is not OPERABLE, or when the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable of withdrawal (Item c.2). This precludes the possibility of criticality upon withdrawal of this control rod. Also, once

(continued)

BASES

LCO (continued)

this alternate (Item c.2) is completed, the LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 4. 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

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

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 4 conditions (i.e., all rods

(continued)

BASES

ACTIONS

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

inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 has been modified by a Note that clarifies the intent of any other LCO's Required Action to insert all control rods. This Required Action includes exiting this Special Operations Applicability by returning the reactor mode switch to the shutdown position. A second Note has been added to Required Action A.1 to clarify that this Required Action is only applicable if the requirements not met are for an affected LCO.

Required Actions A.2.1 and A.2.2 are specified, based on the assumption that the control rod is being withdrawn. If the control rod is still insertable, actions must be immediately initiated to fully insert all insertable control rods and within 1 hour place the reactor mode switch in the shutdown position. Actions must continue until all such control rods are fully inserted. The allowed Completion Time of 1 hour for placing the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

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

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod not insertable, withdrawal of the control rod and removal of the associated CRD must be immediately suspended. If the CRD has been removed, such that the control rod is not insertable, the Required Actions require the most expeditious action be taken to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4 (continued)

drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. UFSAR, Section 14.5.4.3.
2. UFSAR, Section 14.5.4.4.
3. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Single Control Rod Drive (CRD) Removal – Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the removal of a single CRD during refueling operations by imposing certain administrative controls. Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies. The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

The control rod scram function provides backup protection in the event normal refueling procedures, and the refueling interlocks described above fail to prevent inadvertent criticalities during refueling. The requirement for this function to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure the possibility of an inadvertent criticality is precluded, while allowing a single CRD to be removed from a core cell containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refueling Position One-Rod-Out Interlock." The CRD removal also requires isolation of the CRD from the CRD Hydraulic System, thereby causing inoperability of the control rod (LCO 3.9.5, "Control Rod OPERABILITY – Refueling").

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied, these analyses will bound the consequences of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

accidents. Explicit safety analyses in the UFSAR (Refs. 1 and 2) demonstrate that proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement that no other CORE ALTERATIONS are in progress adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1).

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod are inserted and disarmed, and all other control rods are inserted and are incapable of being withdrawn (by insertion of a control rod block).

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 3) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with any of the following LCOs, LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5 not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS.

(continued)

BASES

LCO (continued)

However, if a single CRD removal from a core cell containing one or more fuel assemblies is desired in MODE 5, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented, and this Special Operations LCO applied.

By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement that no other CORE ALTERATIONS are in progress adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal adequately satisfies the backup protection that LCO 3.3.1.1 and LCO 3.9.2 would have otherwise provided. Also, once these requirements (Items a, b, and c) are completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduce the potential for reactivity excursions.

ACTIONS

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

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods inserted) or with the allowances of this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the

(continued)

BASES

ACTIONS

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

CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO. Actions must continue until either Required Action A.2.1 or Required Action A.2.2 is satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5

Verification that all the control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted is required to ensure the SDM is within limits. Verification that the local five by five array of control rods, other than the control rod withdrawn for removal of the associated CRD, is inserted and disarmed, while the scram function for the withdrawn rod is not available, is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Verification that no other CORE ALTERATIONS are being made is required to ensure the assumptions of the safety analysis are satisfied.

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 14.5.4.3

2. UFSAR, Section 14.5.4.4.

3. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal - Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies. When all four fuel assemblies are removed from a cell, the control rod may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

To allow more than one control rod to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypassing the "full-in" position indicators.

APPLICABLE SAFETY ANALYSES

Explicit safety analyses in the UFSAR (Refs. 1, 2 and 3) demonstrate that the functioning of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals, control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full-in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from the cell. With no fuel assemblies in the core cell, the associated control rod has no reactivity control function and is not required to remain inserted. Prior to reloading

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur, as evaluated in the Reference 2 analysis.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 4) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with either LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY – Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal, or CRD removal is desired, all four fuel assemblies are required to be removed from the associated cells. Prior to entering this LCO, any fuel remaining in a cell whose CRD was previously removed under the provisions of another LCO must be removed. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

When fuel is loaded into the core with multiple control rods withdrawn, special spiral reload sequences are used to ensure that reactivity additions are minimized. Spiral reloading encompasses reloading a cell (four fuel locations immediately adjacent to a control rod) on the edge of a continuous fueled region (the cell can be loaded in any sequence). Otherwise, all control rods must be fully inserted before loading fuel. For an unloaded core the spiral reload may commence at either the core center around a "dunking type detector" or, around one of the source range monitors. Placement of the "dunking type detector" in the core cell does not violate the intent of the spiral reload pattern. Fuel assemblies may be loaded into this location when the "dunking type detector" is removed.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4, or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all

(continued)

BASES

APPLICABILITY (continued)

fuel to be removed from cells whose "full-in" indications are allowed to be bypassed. This bypassing must be verified by a second licensed operator or a reactor engineer.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2, Required Action A.3.1, and Required Action A.3.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. In addition, SR 3.10.6.1 must be verified by one licensed operator and a reactor engineer. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 7.6.
2. UFSAR, Section 14.5.4.3.
3. UFSAR, Section 14.5.4.4.
4. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.7 Control Rod Testing – Operating

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Rod Pattern Control," are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a control rod drop accident (CRDA). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests include SDM testing, control rod scram time testing, and control rod friction testing. This Special Operations LCO provides the necessary exemption to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1 and 2. CRDA analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analyses. The RWM provides backup to operator control of the withdrawal sequences to ensure the initial conditions of the CRDA analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analyses of References 1 and 2 may not be preserved. Therefore special CRDA analyses are required to demonstrate that these special sequences will not result in unacceptable consequences, should a CRDA occur during the testing. These analyses, performed in accordance with an NRC approved methodology, are dependent on the specific test being performed.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 3) apply. Special Operations

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence are satisfied. Assurances that the test sequence is followed can be provided by either programming the test sequence into the RWM, with conformance verified as specified in SR 3.3.2.1.8 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator (Reactor Operator or Senior Operator) or other qualified member of the technical staff (i.e., reactor engineer). These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1, "Control Rod Block Instrumentation."

APPLICABILITY

Control rod testing, while in MODES 1 and 2, with THERMAL POWER greater than 10% RTP, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to 10% RTP, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed sequences of LCO 3.1.6.

While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Single Control Rod Withdrawal – Hot Shutdown," or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal – Cold Shutdown," which provide adequate controls

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BASES

APPLICABILITY (continued)

to ensure that the assumptions of the safety analyses of Reference 1 and 2 are satisfied. During these Special Operations and while in MODE 5, the one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock,") and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, provide mitigation of potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern is not in compliance with the special test sequence or the sequence is improperly loaded in the RWM) the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

SURVEILLANCE REQUIREMENTS

SR 3.10.7.1

With the special test sequence not programmed into the RWM, a second licensed operator (Reactor Operator or Senior Operator) or other qualified member of the technical staff (i.e., reactor engineer) is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. A Note is added to indicate that this Surveillance does not need to be met if SR 3.10.7.2 is satisfied.

SR 3.10.7.2

When the RWM provides conformance to the special test sequence, the test sequence must be verified to be correctly loaded into the RWM prior to control rod movement. This Surveillance demonstrates compliance with SR 3.3.2.1.8, thereby demonstrating that the RWM is OPERABLE. A Note has been added to indicate that this Surveillance does not need to be met if SR 3.10.7.1 is satisfied.

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BASES (continued)

REFERENCES

1. UFSAR, Section 14.6.1.2.
2. UFSAR, Section 14.6.3.
3. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test – Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned.

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be verified following fuel movements or control rod replacement within the RPV. The verification must be performed prior to or within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following the refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 5, with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the shutdown or refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the startup/hot standby position, since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup/hot standby position while in MODE 5, is provided by the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation"). The limiting reactivity excursion during startup conditions while in MODE 5 is the control rod drop accident (CRDA).

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1 and 2 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

safety analyses of References 1 and 2 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to verify the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. For the purpose of this test, the protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. 1 and 2). In addition to the added requirements for the RWM, APRM, and control rod coupling, the notch out mode is specified for out of sequence withdrawals. Requiring the notch out mode limits withdrawal steps to a single notch, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 3) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required IRMs, the APRMs are also required to be OPERABLE (LCO 3.3.1.1, Functions 2.a and 2.d) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the approved control rod withdrawal sequence must be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2), or must be verified by a second licensed operator (Reactor Operator or Senior Operator) or other qualified member of the technical staff (i.e., reactor engineer). To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the banked position withdrawal sequence specified in LCO 3.1.6, "Rod Pattern Control," (i.e., out of sequence control rod withdrawals) must be made in the individual notched withdrawal mode to minimize the potential reactivity

(continued)

BASES

LCO (continued)

insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a CRDA and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. Furthermore, since the control rod scram function with the RCS at atmospheric pressure relies solely on the CRD accumulator, it is essential that the CRD charging water header remain pressurized. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup/hot standby position, such that the SDM tests may be performed while in MODE 5.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 5. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With one or more control rods discovered uncoupled during this Special Operation, a controlled insertion of each uncoupled control rod is required; either to attempt recoupling, or to preclude a control rod drop. This controlled insertion is preferred since, if the control rod fails to follow the drive as it is withdrawn (i.e., is "stuck" in an inserted position), placing the reactor mode switch in the shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling is not accomplished, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action A.1 is modified by a Note that allows the RWM to be bypassed if required to allow insertion of the

(continued)

BASES

ACTIONS

A.1 (continued)

inoperable control rods and continued operation. LCO 3.3.2.1, "Control Rod Block Instrumentation," Actions provide additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3

LCO 3.3.1.1, Functions 2.a and 2.d, made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met (SR 3.10.8.1). However, the control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2 requirements) or by a second licensed operator (Reactor Operator or Senior Operator) or other qualified member of the technical staff (i.e., reactor engineer). As noted, either the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3 (continued)

This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These Surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed any time a control rod is withdrawn to the "full-out" notch position, or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved as well as operating experience related to uncoupling events.

SR 3.10.8.6

CRD charging water header pressure verification is performed to ensure the motive force is available to scram the control rods in the event of a scram signal. Since the reactor is depressurized in MODE 5, there is insufficient reactor pressure to scram the control rods. Verification of charging water header pressure ensures that if a scram were to be required, capability for rapid control rod insertion would exist. The minimum charging water header pressure of 940 psig is well below the expected pressure of 1390 to 1580 psig, while still ensuring sufficient pressure for rapid control rod insertion. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 14.6.1.2.
2. UFSAR, Section 14.6.3.
3. 10 CFR 50.36(c)(2)(ii).