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3.7 PLANT SYSTEMS (continued)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

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

The proper functioning of the Reactor Protection System (RPS) and Main Steam Safety Valves (MSSVs) prevents violation of the reactor core SLs.

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Trip System (RTS) setpoints associated with the RTS functions described in Reference 2, in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, RCS Flow, ΔI, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the appropriate operation of the RPS and the MSSVs.

The SLs represent a design requirement for establishing the RTS trip setpoints associated with the RTS functions described in Reference 2. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The figure provided in the COLR shows the loci of points of THERMAL POWER, RCS pressure, and average temperature for which the minimum DNBR is not less than the safety analyses limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, and that the core hot channel exit quality is within the limits defined by the DNBR correlation.

The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB and

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

BASES

SAFETY LIMITS (continued)

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and the core hot channel exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The MSSVs or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in the Licensing Requirements Manual for each unit. In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

The following SL violation responses are applicable to the reactor core SLs. If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

REFERENCES

1. Unit 1 UFSAR, Appendix 1A, "1971 AEC General Design Criteria Conformance." Unit 2 UFSAR, Section 3.1, "Conformance with NRC General Design Criteria."

2. UFSAR, Section 7.2.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of 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. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs). Also, in accordance with GDC 28, "Reactivity Limits" (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2500 psia. During normal operation and AOOs, 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, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. 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. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 50.67, "Accident Source Term" (Ref. 4).

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control

BASES

APPLICABLE SAFETY ANALYSES (continued)

actions are assumed, except that the MSSVs are assumed to open when the steam pressure reaches the safety valve settings, and nominal feedwater supply is maintained.

The Reactor Trip System setpoints (Ref. 5), together with the settings of the pressurizer safety valves and the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of any of the following:

a. Pressurizer power operated relief valves (PORVs),

b. Steam line atmospheric relief valves,

c. Steam Dump System,

d. Reactor Control System,

e. Pressurizer Level Control System, or

f. Pressurizer spray valve.

SAFETY LIMITS

The maximum transient pressure allowed in the Unit 1 and 2 RCS pressure vessels under the ASME Code, Section III, is 110% of design pressure. The Unit 1 RCS piping and fittings are designed to ANSI B31.1 (Ref. 6) and the valves are designed to ASA 16.5 (Ref. 7) which permit a maximum transient pressure of 120% of design. The Unit 2 RCS piping, valves, and fittings are designed to Section III of the ASME Code and have a maximum transient pressure of 110% of design. The most limiting of these two allowances is the 110% of design pressure; therefore, the Unit 1 and 2 SL on maximum allowable RCS pressure is 2735 psig.

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.

BASES

SAFETY LIMIT VIOLATIONS

If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour.

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 50.67, "Accident Source Term," limits (Ref. 4).

The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized.

If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

REFERENCES

1. Unit 1 UFSAR, Appendix 1A, "1971 AEC General Design Criteria Conformance." Unit 2 UFSAR, Section 3.1, "Conformance with NRC General Design Criteria."

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

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

4. 10 CFR 50.67.

5. UFSAR, Section 7.2.

6. ANSI Power Piping Code, B31.1, The American National Standards Institute, 1967.

7. ANSI Steel Pipe Flanges, Flanged Valves, and Fittings, B16.5, The American National Standards Institute.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.8 establish the general requirements applicable to all Specifications 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 unit 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 unit 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 unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of 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.

BASES

LCO 3.0.2 (continued)

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 Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "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/trains 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 unit 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 either:

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

b. The condition of the unit 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 unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is

BASES

LCO 3.0.3 (continued)

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 unit 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 unit 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 unit, 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 unit 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, or

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.

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit 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

BASES

LCO 3.0.3 (continued)

MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 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, 3, and 4, 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 5 and 6 because the unit 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, 3, or 4) 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 unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.15, "Fuel Storage Pool Water Level." LCO 3.7.15 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool and during movement of fuel assemblies over irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.15 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Actions of LCO 3.7.15 of "Suspend movement of irradiated fuel assemblies in the fuel storage pool and suspend movement of fuel assemblies over irradiated fuel assemblies in the fuel storage pool" are the appropriate Required Actions 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 unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit 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.

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

BASES

LCO 3.0.4 (continued)

with Required Actions that permit continued operation of the unit 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 unit 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 to 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 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.

BASES

LCO 3.0.4 (continued)

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.

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 unit shutdown. In this context, a unit 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, MODE 3 to MODE 4, and MODE 4 to MODE 5.

BASES

LCO 3.0.4 (continued)

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 unit 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 either:

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. If the OPERABILITY of the affected equipment can not be demonstrated, the administrative controls will also ensure the equipment/plant is restored to the required condition in a timely manner. This Specification does not provide time to perform any other preventive or corrective maintenance. Minor corrections such as adjustments of limit switches to correct position indication anomalies are considered within the scope of this Specification.

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.

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

BASES

LCO 3.0.5 (continued)

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 supported systems that have a support system 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 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 unit is maintained in a safe condition are specified in the support system 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' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit 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.

Specification 5.5.11, "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,

BASES

LCO 3.0.6 (continued)

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 train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required.

The cross train 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 B 3.0.6-1),

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

<u>EXAMPLE B 3.0.6-1</u>

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

<u>EXAMPLE B 3.0.6-2</u>

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

<u>EXAMPLE B 3.0.6-3</u>

If System 2 of Train A is inoperable, and System 1 of Train 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.

BASES

LCO 3.0.6 (continued)

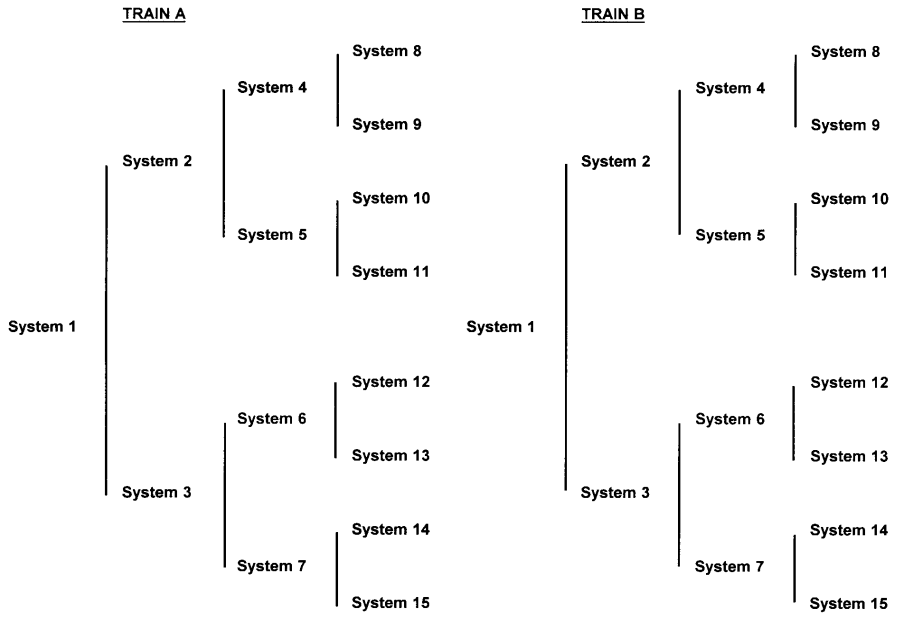

Figure B 3.0-1
Configuration of Trains and Systems

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are 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 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

BASES

LCO 3.0.6 (continued)

address 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 unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCOs 3.1.9 and 3.4.19 allow specified Technical Specification (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 Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

LCO 3.0.8

LCO 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 LCO 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 Technical Specifications (TS) 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.

BASES

LCO 3.0.8 (continued)

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

LCO 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. LCO 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 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.

LCO 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. LCO 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.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 must 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.

BASES

LCO 3.0.8 (continued)

Required Administrative Controls

At least one Auxiliary Feedwater train (including a minimum set of supporting equipment required for its successful operation) not associated with the inoperable snubber(s) must be available when LCO 3.0.8a is used.

At least one Auxiliary Feedwater train (including a minimum set of supporting equipment required for its successful operation) not associated with the inoperable snubber(s), or some alternative means of core cooling (e.g., feed and bleed, fire water system or "aggressive secondary cooldown" using the steam generators), must be available when LCO 3.0.8b is used.

Every time the provisions of LCO 3.0.8 are used, it shall be confirmed that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing the system's required safety or support functions for postulated design loads other than seismic loads. LCO 3.0.8 does not apply to non-seismic snubbers. In addition, a record of the design function of the inoperable snubber (i.e., seismic versus non-seismic), the implementation of any Tier 2 restrictions, and the associated plant configuration shall all be available on a recoverable basis for NRC staff inspection.

Utilization of LCO 3.0.8

Sections A, B, C, D and E, extracted from the TSTF-372, Revision 4, Implementation Guidance document, dated October 2005, describe the steps to be followed when utilizing LCO 3.0.8.

A. Determine Whether a Technical Specification System is Rendered Inoperable by a Nonfunctional Snubber

When a snubber is to be rendered incapable of performing its related support function (i.e., nonfunctional) for testing or maintenance or is discovered to not be functional, it must be determined whether any Technical Specification (TS) system(s) require the affected snubber(s) for system OPERABILITY, and whether the plant is in a MODE or specified condition in the Applicability that requires the supported TS system(s) to be OPERABLE.

1. If an analysis determines that the supported TS system(s) do not require the snubber(s) to be functional in order to support the OPERABILITY of the system(s), LCO 3.0.8 is not needed.

BASES

LCO 3.0.8 (continued)

2. If the LCO(s) associated with any supported TS system(s) are not currently applicable (i.e., the plant is not in a MODE or other specified condition in the Applicability of the LCO), LCO 3.0.8 is not needed.

3. If the supported TS system(s) are inoperable for reasons other than snubbers, LCO 3.0.8 cannot be used.

LCO 3.0.8 is an allowance, not a requirement. When a snubber is nonfunctional, any supported TS system(s) may be declared inoperable instead of using LCO 3.0.8.

B. Determine the Design Basis of the Nonfunctional Snubber

The NRC Safety Evaluation associated with License Amendments 279 and 162 only considered the loss of the ability of a snubber to respond to a seismic event. However, some snubbers have design functions other than response to a seismic event. The inability to perform these non-seismic design functions were not considered or justified in NRC Safety Evaluation associated with License Amendments 279 and 162. Therefore, when a snubber is to be rendered nonfunctional for testing or maintenance or is discovered to not be functional, the design function of the snubber must be determined in order to determine if LCO 3.0.8 may be used.

1. If the design function of the snubber is to react to only seismic loads, LCO 3.0.8 may be applied.

2 If the design function of the snubber includes both seismic loads and nonseismic loads (e.g., thrust loads, blowdown loads, waterhammer loads, steamhammer loads, LOCA loads, and pipe rupture loads), any TS systems supported by the nonfunctional snubber must be able to remain OPERABLE if subjected to the non-seismic loads with the snubber removed. If the supported TS system will remain OPERABLE when subjected to non-seismic loads, LCO 3.0.8 may be applied. Otherwise, LCO 3.0.8 may not be applied to TS systems supported by the nonfunctional snubber.

3. If the design function of the snubber includes only non-seismic loads (e.g., thrust loads, blowdown loads, waterhammer loads, steamhammer loads, LOCA loads, and pipe rupture loads), LCO 3.0.8 cannot be applied to the TS systems supported by the nonfunctional snubber. However, if it can be confirmed that snubber is not needed for OPERABILITY of the TS system, LCO 3.0.8 is not needed.

BASES

LCO 3.0.8 (continued)

As stated in the Required Administrative Controls section, every time LCO 3.0.8 is used for TS systems supported by nonfunctional snubbers whose design loads include non-seismic loads, licensees must be able to produce a record of the design function of the nonfunctional snubber (i.e., seismic vs. non-seismic).

This record does not have to be created prior to or following use of LCO 3.0.8, but must be able to be created or produced if requested. For example, if a system engineer knows from previous experience that a particular snubber is only designed for seismic loads, it is not necessary to collect existing design documents or create design documents or calculations to demonstrate that fact prior to using LCO 3.0.8. However, if asked to demonstrate the design basis of the snubber, the licensee must be able to produce or create appropriate documentation to support that position.

C. Verify that the Required Safety Functions are Available

The risk evaluation that justifies the use of LCO 3.0.8 assumed that the core could be cooled following a loss of offsite power resulting from a seismic event. The three conditions to ensure this capability are described in the Required Administrative Controls section.

D. Consider Effects on Plant Risk

When LCO 3.0.8 is applied to TS systems supported by nonfunctional snubbers, the effect of the nonfunctional snubber on plant risk must be considered. There is no requirement to quantitatively assess the risk associated with a nonfunctional snubber when using LCO 3.0.8. It is not required, for example, to consider a train supported by nonfunctional snubbers unavailable in the 10 CFR 50.65(a)(4) risk assessments. All that is required is a qualitative consideration of the use of LCO 3.0.8, such as not removing the snubbers on one train while the opposite train is inoperable. The LCO 3.0.8 requirement to assess and manage risk is met by programs to comply with the requirements of paragraph (a)(4) of the Maintenance Rule, 10 CFR 50.65, to assess and manage risk resulting from maintenance activities.

E. Respond to Emergent Conditions

Should plant conditions change while LCO 3.0.8 is being used, an evaluation must be performed to ensure the requirements of Sections A, C and D above, are still met. If these requirements are not met, LCO 3.0.8 cannot be used to consider the supported TS system OPERABLE.

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 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 not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit 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 test exception are only applicable when the test exception 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. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

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

BASES

SR 3.0.1 (continued)

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 maintenance 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 maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit 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.

An example of this process is:

Auxiliary feedwater (AFW) pump turbine maintenance during refueling that requires testing at steam pressures > 600 psig. However, if other appropriate testing is satisfactorily completed, the AFW System can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the 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).

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 25% surveillance interval extension per SR 3.0.2 also does not apply to Inservice Testing Program (IST) frequencies which are greater than

BASES

SR 3.0.2 (continued)

2 years, per Specification 5.5.4.b. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Containment Leakage Rate Testing Program (per Specification 5.5.12). 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.

The basis for this delay period includes consideration of unit 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 unit conditions, operating situations, or requirements of regulations (e.g., prior to entering

BASES

SR 3.0.3 (continued)

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 unit 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, NRC 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 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 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

BASES

SR 3.0.3 (continued)

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 unit. 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 a Surveillance 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, 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.

BASES

SR 3.0.4 (continued)

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 unit shutdown. In this context, a unit 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, MODE 3 to MODE 4, and MODE 4 to MODE 5.

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 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

According to GDC 26, as discussed in Reference 1, the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Control Rod System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

BASES

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on scram.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

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

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and ≤ 280 cal/gm energy deposition for the rod ejection accident), and

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

A limiting accident for the SDM requirements is the main steam line break (MSLB), as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1. The SDM required in MODES 3 and 4 below P-11, with safety injection (SI) blocked, is greater than the SDM required in MODES 3 and 4 below P-11, with SI unblocked. This SDM requirement ensures that the limiting steamline break (SLB) analyzed at the end of core life with RCS T_{avg} equal to 547°F would bound a SLB at lower RCS pressures and temperatures.

In addition to the limiting MSLB transient, the SDM requirement must also protect against:

BASES

APPLICABLE SAFETY ANALYSIS (continued)

a. Inadvertent boron dilution,

b. An uncontrolled rod withdrawal from subcritical or low power condition, and

c. Rod ejection.

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high power level trip or a high pressurizer pressure trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power.

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the limiting accidents that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 50.67, “Accident Source Term,” limits (Ref. 4). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

BASES

APPLICABILITY

In MODE 2 with k_{eff} < 1.0 and in MODES 3, 4, and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits."

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tank, or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For example, assuming that a value of 1.77% $\Delta k/k$ must be restored in MODE 4, the RCS boron concentration can be increased from 1526 ppm to 1747 ppm in approximately 100 minutes, utilizing a 30 gpm flow rate, with a source containing a boron concentration of 7,000 ppm. If a boron worth of 8 pcm/ppm is assumed, this combination of parameters will increase the SDM to 1.77%. These RCS boron concentrations represent typical values for MODE 4 at beginning of life (BOL), and are provided for the purpose of offering a specific example.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2 with $K_{eff} \geq 1.0$, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration,

BASES

SURVEILLANCE REQUIREMENTS (continued)

b. Control bank position,

c. RCS average temperature,

d. Fuel burnup based on gross thermal energy generation,

e. Xenon concentration,

f. Samarium concentration, and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

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

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. UFSAR, Section 14.2.5.1 (Unit 1) and Section 15.1.5 (Unit 2).

3. UFSAR, Section 14.1.4 (Unit 1) and Section 15.4.6 (Unit 2).

4. 10 CFR 50.67.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29, as discussed in Reference 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 anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, 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 demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring 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. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculational models used to generate the safety analysis are adequate.

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

BASES

BACKGROUND (continued)

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection 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. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

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 RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements 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 boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOC conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual 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 reactivity balance of $\pm$ 1% $\Delta k/k$ 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.

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis.

BASES

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days 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.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ 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 6 hours. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed once prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value, if required, must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. UFSAR, Chapter 14 (Unit 1) and Chapter 15 (Unit 2).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11, as discussed in Reference 1, the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of cycle (BOC) MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOC limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the UFSAR accident and transient analyses.

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

BASES

BACKGROUND (continued)

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits, since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2) and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The UFSAR (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when MTC is positive. Such accidents include Rod Withdrawal from Subcritical (Ref. 4), Rod Withdrawal at Power (Ref. 5), Loss of Normal Feedwater Flow (Ref. 6), Loss of Offsite Power (Ref. 7), Loss of Electrical Load (Ref. 8), RCS Depressurization (Ref. 9), Loss of Flow (Ref. 10), Locked Rotor (Ref. 11) and Rod Ejection (Ref. 12). The consequences of accidents that cause core overcooling must be evaluated when MTC is negative. Such accidents include Feedwater Flow Increase (Ref. 13), Feedwater Temperature Decrease (Ref. 14) and Steamline Break (Ref. 15).

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOC or EOC life. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOC and EOC. An EOC measurement or analytical check (Ref. 16) of the EOC MTC is conducted when the RCS boron concentration reaches approximately 300 ppm. The measured or calculated value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

BASES

APPLICABLE SAFETY ANALYSES (continued)

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR and Figure 3.1.3-1 to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in the safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The maximum upper (most positive) MTC limit occurs near BOC, all rods out (ARO), hot zero power (HZP), no xenon (NoXe) conditions. Note that in cores containing substantial amounts of burnable absorber in the form of Integral Fuel Burnable Absorber (IFBA), the burnup of most positive MTC under the above conditions may not be at startup, but at some point up to 100 EFPD after startup. If the core never returns to HZP conditions over this period of operations, this most positive MTC may never be physically realized. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, the upper MTC limit can only be ensured through measurement. The lower MTC limit can be ensured either through measurement or by ensuring the benchmark criteria in WCAP-13749-P-A and the COLR requirements for the calculated revised predicted MTC are satisfied. The Surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOC positive limit is established in Figure 3.1.3-1 and the EOC negative limit is established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor

BASES

APPLICABILITY (continued)

critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the BOC upper MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

As cycle burnup is increased, the RCS boron concentration will, in general, be reduced. Note that in cores containing substantial amounts of burnable absorber in the form of IFBA, the core critical boron concentration may actually slowly increase over the first 100 EFPD after startup because the increase in reactivity due to the burnout of the IFBA may be greater than the decrease in reactivity due to the depletion of the fuel. Using physics calculations, the times in cycle life at which the calculated MTC will meet the LCO requirements can be determined. Note that since the RCS boron concentration can increase over the first 100 EFPD, the calculated MTC may meet the LCO requirement at startup and still not meet the LCO requirement later in the cycle. At the points in core life when the calculated MTC meets the LCO requirement, Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be brought to MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC that is more positive than that assumed in safety analyses.

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

BASES

ACTIONS (continued)

C.1

Exceeding the EOC MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the EOC MTC limit is exceeded, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOC MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOC MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated and/or compensated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOC LCO limit. The 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

In order to assure an accurate result SR 3.1.3.2 must be performed after reaching the equivalent of an equilibrium RTP ARO boron concentration of 300 ppm. SR 3.1.3.2 is modified by four Notes that include the following requirements:

BASES

SURVEILLANCE REQUIREMENTS (continued)

a. The SR is not required to be performed until 7 effective full power days (EFPDs) after reaching the equivalent of an equilibrium RTP ARO boron concentration of 300 ppm.

b. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOC limit.

c. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

d. SR 3.1.3.2 is not required to be performed provided that the benchmark criteria specified in WCAP-13749-P-A and the COLR requirements for the calculated revised predicted MTC are satisfied.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. UFSAR Chapter 14 (Unit 1) and Chapter 15 (Unit 2).

3. WCAP 9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

4. UFSAR Section 14.1.1 (Unit 1) and Section 15.4.1 (Unit 2).

5. UFSAR Section 14.1.2 (Unit 1) and Section 15.4.2 (Unit 2).

6. UFSAR Section 14.1.8 (Unit 1) and Section 15.2.7 (Unit 2).

7. UFSAR Section 14.1.11 (Unit 1) and Section 15.2.6 (Unit 2).

8. UFSAR Section 14.1.7 (Unit 1) and Sections 15.2.2 and 15.2.3 (Unit 2).

9. UFSAR Section 14.1.15 (Unit 1) and Section 15.6.1 (Unit 2).

10. UFSAR Sections 14.1.5 and 14.2.9 (Unit 1) and Sections 15.3.1 and 15.3.2 (Unit 2).

BASES

REFERENCES (continued)

11. UFSAR Section 14.2.7 (Unit 1) and Section 15.3.3 (Unit 2).

12. UFSAR Section 14.2.6 (Unit 1) and Section 15.4.8 (Unit 2).

13. UFSAR Section 14.1.9 (Unit 1) and Section 15.1.2 (Unit 2).

14. UFSAR Section 14.1.9 (Unit 1) and Section 15.1.1 (Unit 2).

15. UFSAR Section 14.2.5.1 (Unit 1) and Section 15.1.5 (Unit 2).

16. WCAP-13749-P-A, “Safety Evaluation Supporting the Conditional Exemption of the Most Negative EOL Moderator Temperature Coefficient Measurement,” March 1997 (Westinghouse Proprietary).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (i.e., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Capability" as discussed in Reference 1, and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Mechanical or electrical failures may cause a control or shutdown rod to become inoperable or to become misaligned from its group. Rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

The RCCAs are divided among control banks and shutdown banks. Each bank is further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups, the groups are moved in a staggered fashion, but always within one step of each other. There are four control banks and two shutdown banks.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern,

BASES

BACKGROUND (continued)

using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is approximately halfway withdrawn. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Rod Position Indication (RPI) System for Unit 1 and the Digital Rod Position Indication (DRPI) System for Unit 2.

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI and DRPI systems provide an accurate indication of actual rod position, but at a lower precision than the step counters. These systems are based on inductive analog signals from a series of coils spaced along a hollow tube. The RPI System is capable of monitoring rod position within ± 12 steps. To increase the reliability of the DRPI System, the inductive coils are connected alternately to data system A or B. Thus, if one data system fails, the DRPI will go on half accuracy. The DRPI System is capable of monitoring rod position within ± 4 steps, for full accuracy, and +4, -10 steps at half accuracy with data system A, and +10, -4 steps at half accuracy with data system B.

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

1. Specified acceptable fuel design limits or

BASES

APPLICABLE SAFETY ANALYSIS (continued)

2. Reactor Coolant System (RCS) pressure boundary integrity and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 4). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on control rod OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The control rod OPERABILITY requirements (i.e., trippability) are separate from the alignment requirements, which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment. The rod OPERABILITY requirement is satisfied provided the rod will fully insert in the required rod drop time assumed in the safety analysis. Rod control malfunctions that result in the inability to move a rod (e.g., rod lift coil failures), but that do not impact trippability, do not result in rod inoperability.

The requirement to maintain the rod alignment to within plus or minus 12 steps is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in some cases a total misalignment from fully withdrawn to fully inserted is assumed.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis.

The rod alignment requirements of this LCO may be met by determining rod position in accordance with Rod Position Indication Specifications 3.1.7.1 (Unit 1) and 3.1.7.2 (Unit 2). The ACTIONS of the Rod Position Indication specifications provide alternate methods for determining rod position if a position indicator is inoperable. If the ACTIONS of a Rod Position Indication specification are applicable, the alternate method(s) for determining rod position specified in the applicable ACTIONS may be used to meet the alignment requirements of this LCO.

The LCO requirements are modified by a Note that is only applicable to Unit 1. The Note provides an exception to verifying the LCO requirements are met during rod motion and for the first hour following rod motion. The exception is necessary to accommodate the thermal stabilization required after rod movement for the Unit 1 RPI System. The RPI System requires time to achieve thermal equilibrium after rod movement in order to provide indication within the required accuracy. During rod motion and the time allowed for thermal soak after rod motion, the group demand counters provide the primary indication of precise rod position with the RPI channels displaying general rod movement information. Therefore, comparison between the two indications to verify the LCO requirements are met is not required during the time specified in this Note.

BASES

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which the reactor is critical and power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are typically bottomed and the reactor is shut down and not producing power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN," for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are inoperable (i.e., untrippable), there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration and restoring SDM.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a rod of maximum worth.

A.2

If the inoperable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable. If the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant, and operation may proceed without further restriction.

BASES

ACTIONS (continued)

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 15 steps from the top of the core would require a significant power reduction, since control bank D must be moved fully in and control bank C must be moved in to approximately 100 to 115 steps.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, THERMAL POWER must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to $\leq$ 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded. The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

BASES

ACTIONS (continued)

Verifying that $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are within the required limits ensures that current operation at ≤ 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F_{\Delta H}^N$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. The accident analyses presented in UFSAR Chapter 14 (Unit 1) and Chapter 15 (Unit 2) (Ref. 3) that may be adversely affected will be evaluated to ensure that the analysis results remain valid for the duration of continued operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases of LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

BASES

ACTIONS (continued)

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that is only applicable to Unit 1. The Note provides an exception to performing the SR during rod motion and for the first hour following rod motion. The exception is consistent with the Unit 1 LCO exception Note and is necessary to allow for thermal stabilization and accurate rod position indication. During rod motion and the time allowed for thermal soak after rod motion, the group demand counters provide the primary indication of precise rod position with the RPI channels displaying general rod movement information. Therefore, comparison between the two indications to verify the LCO requirements are met is not required during the time specified in this Note. If the SR comes due during the time allowed by the Note, and the RPI has not stabilized within the required accuracy, the SR should be performed as soon as possible after the time provided by the Note expires. In order to facilitate the thermal stabilization of the RPI during the one-hour thermal soak, absolute rod motion should be limited to six steps.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.2

Verifying each rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2 with $K_{eff} \geq 1.0$, tripping each rod would result in radial or axial power tilts, or oscillations. Exercising each individual rod provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each rod by 10 steps will not cause radial or axial power tilts, or oscillations, to occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Between required performances of SR 3.1.4.2 (determination of rod OPERABILITY by movement), if a rod(s) is discovered to be immovable, but remains trippable the rod(s) is considered to be OPERABLE. At any time, if a rod(s) is immovable, a determination of the trippability (OPERABILITY) of the rod(s) must be made, and appropriate action taken.

For Unit 1 only. The RPI System requires time to achieve thermal equilibrium after rod movement in order to provide accurate rod position indication. During rod motion and the time allowed for thermal soak after rod motion, the group demand counters provide the primary indication of precise rod position with the RPI channels displaying general rod movement information. Considering the time it takes to stabilize the RPI and the relatively short time it takes to perform this SR, it is not required that the RPI show a full 10 step movement in order to confirm freedom of movement. The 10-step requirement of this SR is the minimum required change in demand counter indication that should result in a sufficient change in the RPI to determine freedom of movement.

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature $\geq$ 500°F to simulate a reactor trip under actual conditions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. 10 CFR 50.46.

3. UFSAR, Chapter 14 (Unit 1) and Chapter 15 (Unit 2).

4. UFSAR, Section 14.1.3 (Unit 1) and Section 15.4.3 (Unit 2).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" as discussed in Reference 1, and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and two shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCOs 3.1.7.1 (Unit 1) and 3.1.7.2 (Unit 2), "Rod Position Indication," for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This

BASES

BACKGROUND (continued)

provides available negative reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod.

The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

   1. Specified acceptable fuel design limits or

   2. RCS pressure boundary integrity and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are typically fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown banks to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2, and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are withdrawn before the control banks are withdrawn during a unit startup.

The primary means for verifying that the insertion limits are met is the associated group demand position indicators. Variations in individual rod position indication from the demand position indication are acceptable. Specifications 3.1.4, "Rod Group Alignment Limits," 3.1.7.1 (Unit 1) and 3.1.7.2 (Unit 2), "Rod Position Indication" provide the appropriate limits and Actions for individual rod position indication.

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

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. 10 CFR 50.46.

3. UFSAR, Chapter 14 (Unit 1) and Chapter 15 (Unit 2).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" as discussed in Reference 1, and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and two shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCOs 3.1.7.1 (Unit 1) and 3.1.7.2 (Unit 2), "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. An example is provided for information only in Figure B 3.1.6-1. The control banks are required to be at or above the insertion limit lines.

Figure B 3.1.6-1 also indicates how the control banks are moved in an overlap pattern. Overlap is the distance traveled together by two control banks. Overlap is a function of the fully withdrawn position defined in the COLR, and the tip-to-tip relationship shown on the figure. On the figure, the tip-to-tip relationship is shown as the difference between control bank C and D positions at 8% power, or 130 steps.

BASES

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. Specified acceptable fuel design limits or

   2. Reactor Coolant System pressure boundary integrity and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that the allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 4).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 5).

The insertion limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

BASES

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2 normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlaps limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 2 with $k_{eff} < 1.0$, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits. The required insertion limits are specified in the COLR.

The primary means for verifying the required control bank position is the associated group demand position indicators. Variations in individual rod position indication from the demand position indication are acceptable. Specifications 3.1.4, "Rod Group Alignment Limits," 3.1.7.1 (Unit 1) and 3.1.7.2 (Unit 2), "Rod Position Indication" provide the appropriate limits and Actions for individual rod position indication.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

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

The primary means for verifying that the insertion limits are met is the associated group demand position indicators. Variations in individual rod position indication from the demand position indication are acceptable. Specifications 3.1.4, "Rod Group Alignment Limits," 3.1.7.1 (Unit 1) and 3.1.7.2 (Unit 2), "Rod Position Indication" provide the appropriate limits and Actions for individual rod position indication.

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The primary means for verifying that the sequence and overlap limits are met is the associated group demand position indicators. Variations in individual rod position indication from the demand position indication are acceptable. Specifications 3.1.4, "Rod Group Alignment Limits," 3.1.7.1 (Unit 1) and 3.1.7.2 (Unit 2), "Rod Position Indication" provide the appropriate limits and Actions for individual rod position indication.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. 10 CFR 50.46.

3. UFSAR, Chapter 14 (Unit 1) and Chapter 15 (Unit 2).

4. UFSAR, Section 3.3.2.6 (Unit 1) and Section 4.3.2.5 (Unit 2).

5. UFSAR, Section 3.3.2.5 (Unit 1) and Section 4.3.2.4 (Unit 2).

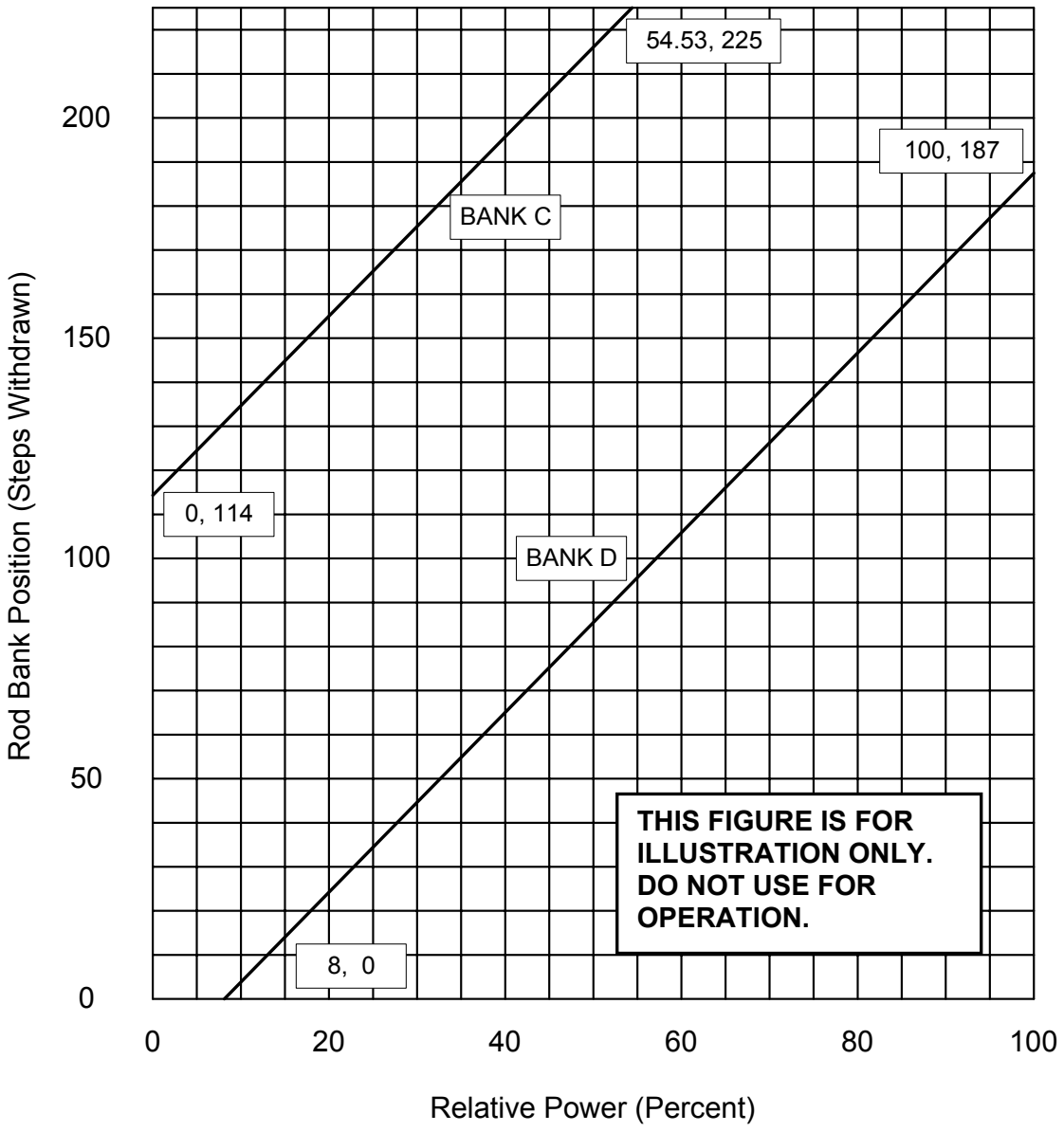

Figure B 3.1.6-1 (page 1 of 1)
Control Bank Insertion vs. Percent RTP

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Rod Position Indication

B.3.1.7.1 Unit 1 Rod Position Indication

BASES

BACKGROUND

According to GDC 13, as discussed in Reference 1, instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7.1 is required to ensure OPERABILITY of the control rod position indication system to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including rod position, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank is further subdivided into two groups to provide for precise reactivity control.

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Rod Position Indication (RPI) System.

BASES

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI System provides an accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from coils spaced along a hollow tube. The maximum uncertainty is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and RPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches.

One method for determining each rod position is the indicators on the vertical board. A secondary method of determining rod position is the in-plant computer. Either the vertical board indicators or in-plant computer is sufficient to comply with this specification. The in-plant computer receives the same inputs from ARPI as the vertical board indicators and provides resolution equivalent to or better than the vertical board indicators. The in-plant computer also provides a digital readout of each rod position which eliminates interpolation and parallax errors inherent to analog scales. When an IPC computer point(s) is used as the primary means of rod position indication, administrative controls require the control room staff to continuously display the IPC computer point(s) in the control room.

Due to the need for the control rod drive shaft to reach thermal equilibrium for accurate individual rod position indication, the group demand counter is considered the primary indicator of precise rod position information during rod movement and for the first hour following rod motion. The RPI channels may only display general rod movement information during this time. A one-hour thermal soak is allowed before the RPI channels must perform within the required accuracy. In order to facilitate the thermal stabilization of the RPI during the one-hour thermal soak, absolute rod motion should be limited to six steps.

BASES

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indication system channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The control rod position indication system monitors control rod position, which is an initial condition of the accident analyses.

LCO

LCO 3.1.7.1 specifies that the RPI System and the Bank Demand Position Indication System be OPERABLE. For the control rod position indication system to be OPERABLE requires meeting the SR of the LCO and the following:

a. The RPI System indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits,"

b. For the RPI System there are no failed coils, and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the RPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the RPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the safety analysis (that specified control rod group insertion limits).

BASES

LCO (continued)

These requirements ensure that rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

APPLICABILITY

The requirements on the RPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

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

When the RPI System indicates one or more potentially misaligned rods, prompt action must be taken to determine if the rod is actually misaligned or if there is a problem with the RPI System. In order to make the prompt determination, Required Action A.1 specifies that the affected rod position must be verified by measuring the associated RPI channel primary voltage within 15 minutes. If the results of the RPI channel primary voltage measurement indicate that the affected rod is misaligned, Required Action A.2.1 specifies that the applicable Conditions and Required Actions of LCO 3.1.4, "Rod Group Alignment Limits" be entered within 15 minutes. If the results of the RPI channel primary voltage measurement do not indicate a misaligned rod, Required Action A.2.2 specifies that the affected RPI is declared inoperable and the applicable Conditions and Required Actions of LCO 3.1.7.1, "Unit 1 Rod Position Indication" be entered within 15 minutes.

BASES

ACTIONS (continued)

Condition A is modified by a Note that provides an exception to applying Condition A to misalignment indications that occur during rod motion and for up to one hour following rod motion. The exception is necessary to accommodate the thermal stabilization required after rod movement for the RPI. The RPI System requires time to achieve thermal equilibrium after rod movement in order to provide indication within the required accuracy. During rod motion and the time allowed for thermal soak after rod motion, the group demand counters provide the primary indication of precise rod position with the RPI channels displaying general rod movement information. Reliance on the demand counter indication for up to one hour following rod motion is acceptable for determining rod position and therefore, Condition A is not applicable until after the one hour thermal soak provided by the Note.

B.1

When one RPI channel per group fails, the position of the rod may still be determined indirectly by use of the movable incore detectors or by measuring the rod position channel primary voltage. The Required Action may also be satisfied by using the movable incore detectors to ensure at least once per 8 hours that $F_Q(Z)$ satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Actions of Condition D below are applicable. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

B.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors.

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action B.1 above.

BASES

ACTIONS (continued)

C.1, C.2, C.3, and C.4

When more than one RPI per group fail, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Placing the Rod Control System in manual assures unplanned rod motion will not occur. Placing the Rod Control System in manual together with the indirect position determination available via movable incore detectors or by measuring the rod position channel primary voltage will minimize the potential for rod misalignment. The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this Condition.

Monitoring and recording Reactor Coolant System T_{avg} help assure that significant changes in power distribution and SDM are avoided. The once per hour Completion Time is acceptable because only minor fluctuations in RCS temperature are expected at steady state plant operating conditions.

The position of the rods may be determined indirectly by use of the movable incore detectors or by measuring the rod position channel primary voltage. The Required Action may also be satisfied by using the movable incore detectors to ensure at least once per 8 hours that $F_Q(Z)$ satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the non-indicating rods have not been moved. Verification of control rod position once per 8 hours is adequate for allowing continued full power operation for a limited, 24 hour period, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. The 24 hour Completion Time provides sufficient time to troubleshoot and restore the RPI system to operation while avoiding the plant challenges associated with the shutdown without full rod position indication.

Based on operating experience, normal power operation does not require excessive rod movement. If one or more rods has been significantly moved, the Required Actions of Condition D below is required.

D.1.1, D.1.2, and D.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of B.1 or C.3, as applicable are still appropriate but must be initiated immediately under Required Action D.1.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

BASES

ACTIONS (continued)

If, within 8 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions or reduce power to ≤ 50% RTP.

E.1.1 and E.1.2

With one demand position indicator per bank inoperable, the rod positions can be determined by the RPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indication system for each control and shutdown rod is OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate.

E.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Condition D or reduce power to ≤ 50% RTP.

F.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1.1

Verification that each control bank benchboard group step demand counter agrees within ±2 steps with the solid state indicators in the logic cabinet helps to assure that the benchboard demand counters are indicating correctly and that the demand counters may be relied on during rod movement and for the first hour following rod movement for the primary indication of precise rod position.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

SR 3.1.7.1.2

Verification that the RPI agrees with the demand position within ±12 steps ensures that the RPI is operating correctly. The verification of RPI and demand position indication within the required 12 steps over the full range of indicated rod travel is accomplished by comparisons of the indications at specific rod positions (identified in the applicable surveillance procedure) and calibrations as necessary to ensure the required accuracy is achieved.

This Surveillance is performed prior to reactor criticality after each removal of the reactor head, as there is the potential for unnecessary plant transients if the SR were performed with the reactor at power.

The SR is modified by a Note. The Note provides an exception to the SR during rod motion and for the first hour following rod motion. The exception is necessary to allow for thermal stabilization and accurate rod position indication. During rod motion and the time allowed for thermal soak after rod motion, the group demand counters provide the primary indication of precise rod position with the RPI channels displaying general rod movement information. Therefore, comparison between the two indications to verify the LCO requirements are met is not required during the time specified in this Note. If the SR comes due during the time allowed by the Note, and the RPI has not stabilized within the required accuracy, the SR should be performed as soon as possible after the time provided by the Note expires. In order to facilitate the thermal stabilization of the RPI during the one-hour thermal soak, absolute rod motion should be limited to six steps.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance."

2. UFSAR, Chapter 14 (Unit 1).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Rod Position Indication

B.3.1.7.2 Unit 2 Rod Position Indication

BASES

BACKGROUND

According to GDC 13, as discussed in Reference 1, instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7.2 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including rod position, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank is further subdivided into two groups to provide for precise reactivity control.

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

BASES

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The DRPI System provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is 6 steps. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one system fails, the DRPI will go on half accuracy with an effective coil spacing of 7.5 inches, which is 12 steps. Therefore, the normal indication accuracy of the DRPI System is ± 4 steps, for full accuracy, and +4, -10 steps at half accuracy with data system A, and +10, -4 steps at half accuracy with data system B. As such, only one data system (A or B) is required for an OPERABLE DRPI System indicating within 12 steps of the group step counter demand position indicator. With an indicated deviation of 12 steps between the group step counter and DRPI, the maximum deviation between actual rod position and the demand position could be 22 steps, or 13.75 inches.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The control rod position indicators monitor control rod position, which is an initial condition of the accident analyses.

BASES

LCO

LCO 3.1.7.2 specifies that the DRPI System (data system A or B) and the Bank Demand Position Indication System be OPERABLE. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The required DRPI System indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits,"

b. For the required DRPI System there are no failed coils, and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the DRPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the DRPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the safety analysis (that specified control rod group insertion limits).

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

APPLICABILITY

The requirements on the DRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

BASES

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

A.1

When one DRPI channel per group fails, the position of the rod may still be determined indirectly by use of the movable incore detectors. The Required Action may also be satisfied by using the movable incore detectors to ensure at least once per 8 hours that $F_Q(Z)$ satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of C.1.1 and C.1.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors.

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1, B.2, B.3, and B.4

When more than one DRPI per group fail, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Placing the Rod Control System in manual assures unplanned rod motion will not occur. Placing the Rod Control System in manual together with the indirect position determination available via movable incore detectors will minimize the potential for rod misalignment. The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this Condition.

BASES

ACTIONS (continued)

Monitoring and recording reactor coolant T_{avg} help assure that significant changes in power distribution and SDM are avoided. The once per hour Completion Time is acceptable because only minor fluctuations in RCS temperature are expected at steady state plant operating conditions.

The position of the rods may be determined indirectly by use of the movable incore detectors. The Required Action may also be satisfied by using the movable incore detectors to ensure at least once per 8 hours that $F_Q(Z)$ satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Verification of control rod position once per 8 hours is adequate for allowing continued full power operation for a limited, 24 hour period, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. The 24 hour Completion Time provides sufficient time to troubleshoot and restore the DRPI system to operation while avoiding the plant challenges associated with the shutdown without full rod position indication.

Based on operating experience, normal power operation does not require excessive rod movement. If one or more rods has been significantly moved, the Required Action of C.1.1 and C.1.2 below is required.

C.1.1, C.1.2, and C.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of A.1 or B.3, as applicable are still appropriate but must be initiated immediately under Required Action C.1.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

If, within 8 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions or reduce power to ≤ 50% RTP.

BASES

ACTIONS (continued)

D.1.1 and D.1.2

With one demand position indicator per bank inoperable, the rod positions can be determined by the DRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate.

D.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Action A.1 or reduce power to ≤ 50% RTP.

E.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.2.1

Verification that the DRPI agrees with the demand position within ±12 steps ensures that the DRPI is operating correctly. Since the DRPI does not display the actual shutdown rod positions between 18 and 210 steps, only points within the indicated ranges are required in comparison.

This Surveillance is performed prior to reactor criticality after each removal of the reactor head, as there is the potential for unnecessary plant transients if the SR were performed with the reactor at power.

REFERENCES

1. Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Unborated Water Source Isolation Valves

BASES

BACKGROUND

During MODES 4, 5, and 6 isolation valves for flow paths from the Primary Grade Water System to the charging system must be closed to prevent unplanned boron dilution of the reactor coolant. The isolation valves must be secured in the closed position.

The Chemical and Volume Control System is capable of supplying borated and unborated water to the Reactor Coolant System (RCS) through various flow paths. Since an unplanned positive reactivity addition made by reducing the boron concentration is inappropriate during MODES 4, 5, and 6, isolation of the required unborated water sources prevents an unplanned boron dilution.

APPLICABLE SAFETY ANALYSES

The possibility of an inadvertent boron dilution event (Ref. 1) occurring in MODES 4, 5, and 6 is precluded by adherence to this LCO, which requires that potential dilution sources be isolated. Closing the required valves prevents the flow of unborated water to the RCS. The valves are used to isolate unborated water sources. These valves have the potential to indirectly allow dilution of the RCS boron concentration. By isolating unborated water sources, a safety analysis for an uncontrolled boron dilution accident in accordance with the Standard Review Plan (Ref. 2) is not required for MODES 4, 5, and 6.

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that flow paths from the Primary Grade Water System to the RCS (via the charging system) be isolated to prevent unplanned boron dilution during MODES 4, 5, and 6 and thus avoid a reduction in SDM.

In order to meet the requirements of the LCO, the following valves must be isolated:

For Unit 1 either a) 1CH-90 or b) 1CH-91 and 1CH-93.

For Unit 2 either a) 2CHS-37 and 2CHS-828 or b) 2CHS-91, 2CHS-96 and 2CHS-138.

BASES

LCO (continued)

The LCO requirement to secure closed each valve used to isolate unborated water sources is modified by a Note. The Note provides an exception to the LCO requirement that allows unborated water source isolation valves to be opened under administrative control for planned boron dilution or makeup activities.

APPLICABILITY

In MODES 4, 5, and 6, this LCO is applicable to prevent an inadvertent boron dilution event by ensuring isolation of the required sources of unborated water to the RCS.

For all other MODES, the boron dilution accident was analyzed and was found to be capable of being mitigated.

ACTIONS

The ACTIONS Table has been modified by a Note that allows separate Condition entry for each unborated water source isolation valve.

A.1

Continuation of CORE ALTERATIONS and positive reactivity changes is contingent upon maintaining the unit in compliance with this LCO. With any valve used to isolate unborated water sources not secured in the closed position, all operations involving CORE ALTERATIONS and positive reactivity changes must be suspended immediately. The Completion Time of "immediately" for performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

Condition A has been modified by a Note to require that Required Action A.3 be completed whenever Condition A is entered.

A.2

Preventing inadvertent dilution of the reactor coolant boron concentration is dependent on maintaining the required unborated water isolation valves secured closed. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of "immediately" requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position immediately. Once actions are initiated, they must be continued until the valves are secured in the closed position.

BASES

ACTIONS (continued)

A.3

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.1.1.1 (verification of SDM), or SR 3.9.1.1 (verification of boron concentration) must be performed whenever Condition A is entered to demonstrate that the required boron concentration or SDM exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration or to determine the SDM.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

These valves are to be secured closed to isolate the Primary Grade Water System dilution paths. The likelihood of a significant reduction in the boron concentration is remote due to the volume of borated water and the fact that the required unborated water sources are isolated, precluding a dilution. In MODES 4 and 5, the SDM is verified under SR 3.1.1.1 and in MODE 6 the boron concentration is checked under SR 3.9.1.1. This Surveillance demonstrates that the valves are secured closed by direct field observation. The surveillance must be performed within 15 minutes after a planned boron dilution or makeup activity. The requirement to perform this surveillance promptly after completing dilution or makeup activities provides positive control over such activities and assures the affected valves are restored to the secured closed condition after use. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

In order to meet the requirements of the SR, the condition of the following valves must be verified:

For Unit 1 either a) 1CH-90 or b) 1CH-91 and 1CH-93.

For Unit 2 either a) 2CHS-37 and 2CHS-828 or b) 2CHS-91, 2CHS-96 and 2CHS-138.

REFERENCES

1. UFSAR, Section 14.1.4 (Unit 1) and Section 15.4.6 (Unit 2).

2. NUREG-0800, Section 15.4.6.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.9 PHYSICS TESTS Exceptions - MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-1997 (Ref. 3). The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed (Ref. 3).

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

The MODE 2 PHYSICS TESTS required for reload fuel cycles (Ref. 3) are performed in accordance with the requirements described in Reference 3. The required MODE 2 tests are listed below:

a. Critical Boron Concentration - Control Rods Withdrawn,

b. Critical Boron Concentration - Reference Bank Inserted,

c. Control Rod Worth, and

d. Isothermal Temperature Coefficient (ITC).

BASES

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 4). The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-1997 (Ref. 3). Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in LCO 3.1.3, "Moderator Temperature Coefficient (MTC)," LCO 3.1.4, "Rod Group Alignment Limits," LCO 3.1.5, "Shutdown Bank Insertion Limit," LCO 3.1.6, "Control Bank Insertion Limits," and LCO 3.4.2, "RCS Minimum Temperature for Criticality" are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 531°F, and SDM is within the limits provided in the COLR.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR.

As described in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. Test Exception 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

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. One power range neutron flux channel may be bypassed, reducing the number of required channels from 4 to 3. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

BASES

LCO (continued)

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3, and 17.e may be reduced to 3 required channels during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ 531°F,

b. SDM is within the limits provided in the COLR, and

c. THERMAL POWER is ≤ 5% RTP.

In addition to the LCOs listed above the Test Exception provides the following Unit 1 specific exception that may also be used during PHYSICS TESTING:

For Unit 1 only, primary detector voltage measurements may be used to determine the position of rods in shutdown banks A and B and control banks A and B in lieu of the benchboard indicators required by LCO 3.1.7.1.

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The Applicability is stated as "during PHYSICS TESTS initiated in MODE 2" to ensure that the 5% RTP maximum power level is not exceeded. Should the THERMAL POWER exceed 5% RTP, and consequently the unit enter MODE 1, this Applicability statement prevents exiting this Specification and its Required Actions.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

BASES

ACTIONS (continued)

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS lowest T_{avg} is < 531°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 531°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.9.1

The power range and intermediate range neutron detectors are required to be OPERABLE in MODE 2 in accordance with LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel in accordance with the frequency requirement of the referenced RTS surveillances which ensures each channel is tested prior to the initiation of PHYSICS TESTS. The performance of the RTS CHANNEL OPERATIONAL TEST requirements referenced in this SR will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.9.2

Verification that the RCS lowest loop T_{avg} is ≥ 531°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.9.3

Verification that the THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. Verification of the THERMAL POWER during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.9.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration,

b. Control bank position, and

c. RCS average temperature.

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

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.

2. 10 CFR 50.59.

3. ANSI/ANS-19.6.1 - 1997, August 23, 1997.

4. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.10 RCS Boron Limitations < 500°F

BASES

BACKGROUND

The control rod drive mechanisms (CRDMs) are wired into pre-selected RCCA banks, such that the RCCA banks during normal operation (i.e., not in bank select mode) can only be withdrawn in their proper withdrawal sequence. The control of the power supplied to the RCCA banks is such that no more than two RCCA banks can be withdrawn at any time.

When the RCCA banks are capable of being withdrawn from the core, i.e., power supplied to the CRDMs during an approach to criticality for reactor startup, or during maintenance and surveillance testing, there is the potential for an inadvertent RCCA bank withdrawal due to a malfunction of the control rod drive system.

Westinghouse NSAL-00-016 (Ref. 1) discussed the reactor trip functions associated with the Uncontrolled RCCA Bank Withdrawal from a Low Power or Subcritical Condition event (RWFS) (Ref. 2). The primary protection for a RWFS is provided by the Power Range Neutron Flux - Low trip Function. The Source Range Neutron Flux trip Function is implicitly credited as the primary reactor trip function for a RWFS event in MODES 3, 4, or 5, since the Power Range Neutron Flux - Low trip Function is not required to be OPERABLE in these MODES. However, the Source Range Neutron Flux trip Function is not response time tested per SR 3.3.1.14, and therefore can not be considered to be fully OPERABLE to provide protection for a RWFS event in MODES 3, 4, and 5.

NSAL-00-016 also identified that the Power Range Neutron Flux - Low trip Function may not be OPERABLE at RCS temperatures significantly below the hot zero power T_{avg} due to calibration issues associated with shielding caused by the cold water in the downcomer region of the reactor vessel. The low RCS temperature limit for Power Range Neutron Flux Trip Function OPERABILITY is 500°F. Therefore, the Power Range Neutron Flux - Low trip Function may not provide the required protection in and below MODE 3 when RCS temperatures are < 500°F due to the calibration issues described above.

Borating the RCS to greater than an all rods out (ARO) critical boron concentration when the RCCA banks are capable of rod withdrawal provides sufficient SHUTDOWN MARGIN in the event of an RWFS when RCS temperatures are < 500°F.

BASES

APPLICABLE SAFETY ANALYSES

The RCCA bank withdrawal event addressed by this LCO is the RWFS event. An RCCA bank withdrawal event at power is also analyzed, and is addressed by the requirements of other Specifications that are applicable in MODE 1.

The RWFS event assumes a positive reactivity insertion rate that is greater than the worth obtained from the simultaneous withdrawal of the combination of two sequential control banks with the highest combined worth at the maximum withdrawal speed.

The event is assumed to be terminated by the Power Range Neutron Flux - Low trip Function. The Source Range Neutron Flux and Intermediate Range Neutron Flux trip Functions are also available to terminate an RWFS event, but are not explicitly credited in the safety analyses to terminate the event.

The Power Range Neutron Flux - Low trip Function is considered OPERABLE to provide the required protection for an RWFS event when the RCS temperature is ≥ 500°F. This temperature limitation is due to calibration issues associated with shielding caused by cold water in the downcomer region of the reactor vessel. Additionally, although not explicitly analyzed, in MODES 3, 4, and 5, the Source Range Neutron Flux trip Function is implicitly credited to provide protection for an RWFS event.

Since there is no explicit RCCA bank withdrawal analysis performed for MODE 3 when the RCS temperature is < 500°F and in MODES 4 and 5, and the Power Range Neutron Flux - Low trip Function can not be credited to mitigate an RWFS event at RCS temperatures below 500°F, LCO 3.1.10 requires that the RCS boron concentration be greater than the ARO critical boron concentration when the Rod Control System is capable of rod withdrawal in these MODES. This requirement provides sufficient SHUTDOWN MARGIN to prevent the undesirable consequences (i.e., criticality) that could result from an RWFS event.

RCS Boron Limitations < 500°F satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that the boron concentration of the RCS be greater than the ARO critical boron concentration to provide adequate SHUTDOWN MARGIN in the event of an RWFS event.

BASES

APPLICABILITY

In the event of an RWFS, the LCO must be applicable to provide adequate SHUTDOWN MARGIN in the following MODES and specified conditions:

- In MODE 2 with k_{eff} < 1.0 with any RCS cold leg temperature < 500°F and with the Rod Control System capable of rod withdrawal.
- In MODE 3 with any RCS cold leg temperature < 500°F and with the Rod Control System capable of rod withdrawal; and
- In MODES 4 and 5 with the Rod Control System capable of rod withdrawal.

In MODE 6, the requirements of LCO 3.1.10 are not necessary because the rod control system is not capable of rod withdrawal.

In MODE 2 with $k_{eff} \geq 1.0$, in MODE 2 with $k_{eff} < 1.0$ and all RCS cold leg temperatures ≥ 500°F and the Rod Control System capable of rod withdrawal, and in MODE 3 with all RCS cold leg temperatures ≥ 500°F and the Rod Control System capable of rod withdrawal, LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation," ensures that the Power Range Neutron Flux-Low trip Function is OPERABLE to mitigate a potential RWFS event.

In MODE 1, the requirements of LCO 3.1.10 are not applicable since an uncontrolled RCCA bank withdrawal event at power would be mitigated by the Power Range Neutron Flux-High trip Function. This Function is required to be OPERABLE by LCO 3.3.1.

ACTIONS

A.1

If the RCS boron concentration is not within limit, action must be taken immediately to restore the boron concentration to within limit. Borating the RCS to a concentration greater than the ARO critical boron concentration provides sufficient SHUTDOWN MARGIN, if an RWFS event should occur. Initiating action immediately to restore the boron concentration to within the limit provides assurance that the LCO requirement will be restored in a timely manner. The Completion Time is reasonable considering the low probability of an RWFS event occurring while restoring the boron concentration to within the limit. Additionally, although not explicitly credited as a primary trip, the Source Range Neutron Flux trip Function would provide protection from an RWFS event during this period of time.

BASES

ACTIONS (continued)

A.2

If the RCS boron concentration is not within limit, an alternate action is to make the Rod Control System incapable of rod withdrawal. This action precludes a RWFS event from occurring with an inadequate SHUTDOWN MARGIN. Initiating action immediately to make the rod control system incapable of rod withdrawal provides adequate assurance that the unit is promptly placed in a condition in which the boron concentration requirements of the LCO are no longer required to mitigate the consequences of a RWFS event.

A.3

If the RCS boron concentration is not within limit, another alternate action is to restore all RCS cold leg temperatures to ≥ 500°F. At this RCS temperature the Power Range Neutron Flux - Low trip Function would be OPERABLE and provide the necessary protection should a RWFS event occur. Initiating action immediately to restore all RCS cold leg temperatures to ≥ 500°F provides adequate assurance that the unit is promptly placed in a condition in which the boron concentration requirements of the LCO are no longer necessary. Additionally, although not credited as a primary trip, the Source Range Neutron Flux trip Function would provide protection for a RWFS event while RCS Temperature is being increased.

Required Action A.3 is modified by a Note that states it is not applicable in MODES 4 and 5. The Note provides assurance that this Required Action would only be taken in MODES 2 or 3 (i.e., during a unit startup) when the RCS temperature can readily be increased to ≥ 500°F. After the RCS cold leg temperatures are increased to ≥ 500°F, the requirements of LCO 3.1.10 are no longer applicable and protection during a RWFS event is provided by the Power Range Neutron Flux - Low trip Function, which is required to be OPERABLE by LCO 3.3.1.

SURVEILLANCE REQUIREMENTS

SR 3.1.10.1

This SR ensures that the RCS boron concentration is within limit. The boron concentration is determined periodically by chemical analysis.

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

BASES

REFERENCES

1. Westinghouse Nuclear Safety Advisory Letter NSAL-00-016, "Rod Withdrawal from Subcritical Protection in Lower Modes," December 4, 2000.

2. Unit 1 UFSAR, Chapter 14 and Unit 2 UFSAR Chapter 15.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near equilibrium conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents an equilibrium condition, it does not include the variations in the value of $F_Q(Z)$ which are present during nonequilibrium situations such as load following or power ascension.

To account for these possible variations, the equilibrium value of $F_Q(Z)$ is adjusted as $F_Q^W(Z)$ by an elevation dependent factor that accounts for the calculated worst case transient conditions.

Core monitoring and control under non-equilibrium conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

BASES

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large or small break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200°F (Ref. 1),

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 2), and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$ shall be limited by the following relationships:

$F_Q(Z) \leq [CFQ / P]\ K(Z)$ for $P > 0.5$

$F_Q(Z) \leq [CFQ / 0.5]\ K(Z)$ for $P \leq 0.5$

where: CFQ is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

P = THERMAL POWER / RTP

The actual values of CFQ and K(Z) are given in the COLR; however, CFQ is normally a number on the order of 2.40, and K(Z) is a function that looks like the one provided in Figure B 3.2.1-1. Figure B 3.2.1-1 is for illustration purposes only. The actual unit specific K(Z) as a function of core height figures are contained in the COLR.

BASES

LCO (continued)

For Relaxed Axial Offset Control operation, $F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus, both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

An $F_Q^C(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$. Then,

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- NOTE -

An additional measurement uncertainty is to be applied if the number of measured thimbles for the moveable incore detector system is less than or equal to 37 but greater than or equal to 25. The additional uncertainty of (0.01)*[3-(T/12.5)] is added to the measurement uncertainty, 1.05, where T is the total number of measured thimbles. The total uncertainty applied is then 1.03 times the adjusted measurement uncertainty. At least three measured thimbles per core quadrant are also required.

$$F_Q^C(Z) = F_Q^M(Z)\ 1.0815$$

where 1.0815 is a factor that accounts for fuel manufacturing tolerances and flux map measurement uncertainty (Ref. 4).

$F_Q^C(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the incore flux map was taken.

The expression for $F_Q^W(Z)$ is:

$$F_Q^W(Z) = F_Q^C(Z)\ W(Z)$$

where W(Z) is a cycle dependent function that accounts for power distribution transients encountered during normal operation. W(Z) is included in the COLR. The $F_Q^C(Z)$ is calculated at equilibrium conditions.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q^C(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required and if $F_Q^W(Z)$ cannot be maintained within the LCO limits, reduction of the AFD limits is required. Note that sufficient reduction of the AFD limits will also result in a reduction of the core power.

BASES

LCO (continued)

Violating the LCO limits for $F_Q(Z)$ produces unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F_Q^C(Z)$ is $F_Q^M(Z)$ multiplied by a factor accounting for manufacturing tolerances and measurement uncertainties. $F_Q^M(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require power reductions within 15 minutes of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

A reduction of the Power Range Neutron Flux - High trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux - High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Power Range Neutron Flux - High trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux - High trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux - High trip setpoints.

BASES

ACTIONS (continued)

A.3

Reduction in the Overpower ΔT trip setpoints (value of K_4) by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Overpower ΔT trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Overpower ΔT trip setpoints.

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition A is modified by a Note that requires Required Action A.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action A.1, even when Condition A is exited prior to performing Required Action A.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD limits by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, restricts the axial flux distribution such that even if a transient occurred, core peaking factors are not exceeded.

The implicit assumption is that if W(Z) values were recalculated (consistent with the reduced AFD limits), then $F_Q^C(Z)$ times the recalculated W(Z) values would meet the $F_Q(Z)$ limit. Note that complying with this action (of reducing AFD limits) may also result in a power reduction. Hence the need for Required Actions B.2, B.3 and B.4.

BASES

ACTIONS (continued)

B.2

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

B.3

Reduction in the Overpower ΔT trip setpoints value of K_4 by ≥ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

B.4

Verification that $F_Q^W(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the maximum allowable power limit imposed by Required Action B.1 ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition B is modified by a Note that requires Required Action B.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action B.1, even when Condition A is exited prior to performing Required Action B.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

C.1

If Required Actions A.1 through A.4 or B.1 through B.4 are not met within their associated Completion Times, the plant must be placed in a MODE or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by a Note. The Note applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because $F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ are made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 10%, ensures that they are verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_Q(Z)$ was last measured.

SR 3.2.1.1

- NOTE -

An additional measurement uncertainty is to be applied if the number of measured thimbles for the moveable incore detector system is less than or equal to 37 but greater than or equal to 25. The additional uncertainty of (0.01)*[3-(T/12.5)] is added to the measurement uncertainty, 1.05, where T is the total number of measured thimbles. The total uncertainty applied is then 1.03 times the adjusted measurement uncertainty. At least three measured thimbles per core quadrant are also required.

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q^C(Z) = F_Q^M(Z)$ 1.0815 (Ref. 4). $F_Q^C(Z)$ is then compared to its specified limits.

The limit with which $F_Q^C(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q^C(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

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

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because flux maps are taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

The SR Note specifies in part "If measurements indicate that the maximum over z of [$F_Q^C(Z)$/ K(Z)] has increased ...". This statement in the Note refers to the fact that both F_Q^C and K are functions of the axial height. At each applicable core elevation the ratio of $F_Q^C(Z)$ / K(Z) is calculated to determine the maximum ratio (maximum over z). If this maximum ratio has increased since the last set of evaluations, then the Note modifying this SR specifies additional verifications that must be performed.

The limit with which $F_Q^W(Z)$ is compared varies inversely with power above 50% RTP and directly with the function K(Z) provided in the COLR.

The W(Z) Table is provided in the COLR for discrete core elevations. Flux map data are typically taken for 30 to 75 core elevations. $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 10% inclusive and

b. Upper core region, from 90 to 100% inclusive.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The top and bottom 10% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions.

This Surveillance has been modified by a Note that may require more frequent surveillances be performed. If $F_Q^W(Z)$ is evaluated, an evaluation of the expression below is required to account for any increase to $F_Q^W(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

If the two most recent $F_Q(Z)$ evaluations show an increase in the expression maximum over z of [$F_Q^C(Z)$ / K(Z)], it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by the greater of a factor of 1.02 or by an appropriate factor specified in the COLR (Ref. 5) or to evaluate $F_Q(Z)$ more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because peaking factors are generally decreased as power level is increased.

$F_Q(Z)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

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

REFERENCES

1. 10 CFR 50.46, 1974.

2. Regulatory Guide 1.77, Rev. 0, May 1974.

3. 10 CFR 50, Appendix A, GDC 26.

4. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.

5. WCAP-10216-P-A, Rev. 1A, "Relaxation of Constant Axial Offset Control (and) F_Q Surveillance Technical Specification," February 1994.

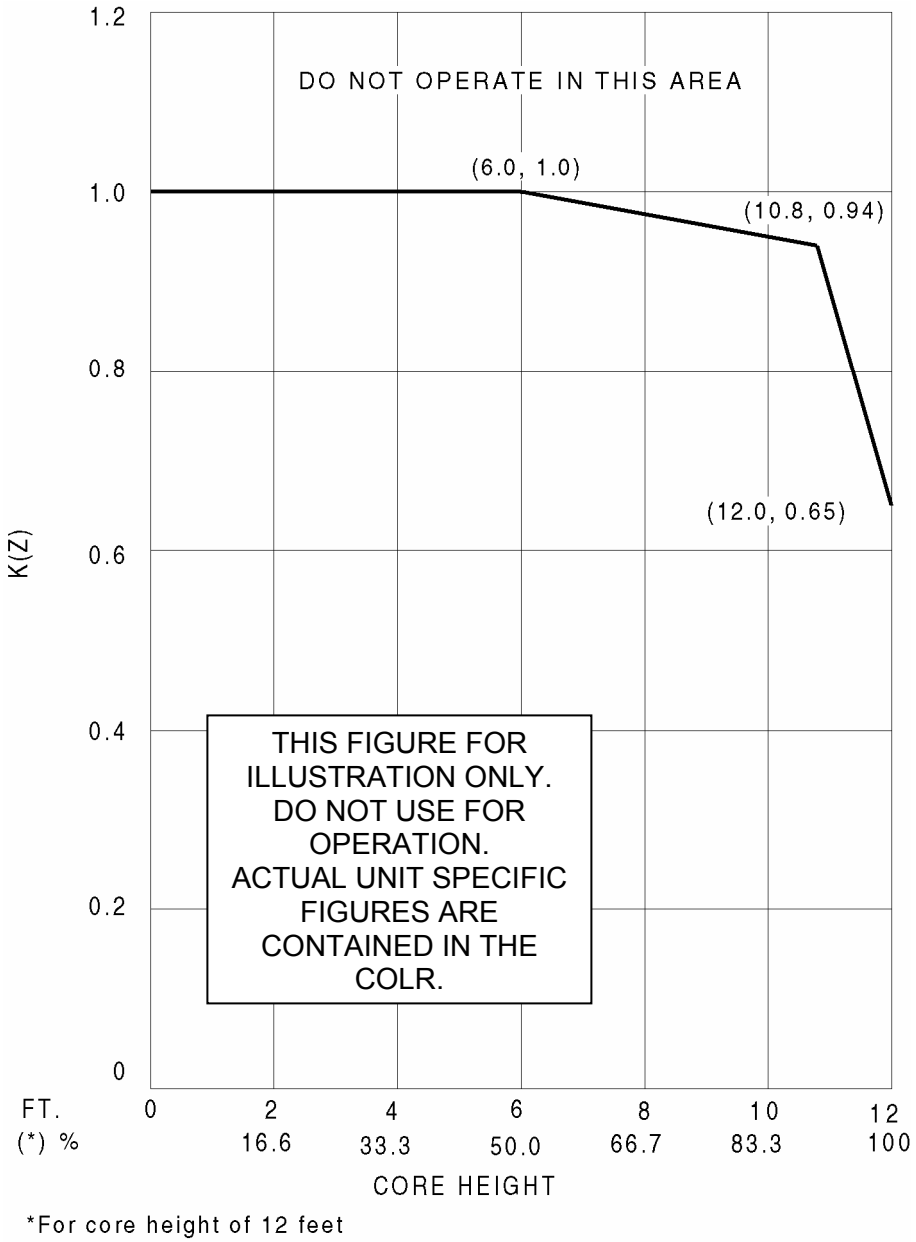

Figure B 3.2.1-1 (page 1 of 1)
K(Z) - Normalized $F_Q(Z)$ as a Function of Core Height

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. The DNB design basis ensures the probability that DNB will not occur on the most limiting fuel rod is at least 95% at a 95% confidence level. This is met by limiting the minimum DNBR to the 95/95 DNB criterion of 1.22 for typical and thimble cells using the WRB-2M Critical Heat Flux (CHF) correlation, and 1.23 for the typical cell and 1.22 for the thimble cell using the WRB-1 CHF correlation. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible

BASES

BACKGROUND (continued)

cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition,

b. During a large or small break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F (Ref. 3),

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 1), and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, the Reactor Coolant System flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis ensures the probability that DNB will not occur on the most limiting fuel rod is at least 95% at a 95% confidence level. This is met by limiting the minimum DNBR to the 95/95 DNB criterion of 1.22 for typical and thimble cells using the WRB-2M CHF correlation, and 1.23 for the typical cell and 1.22 for the thimble cell using the WRB-1 CHF correlation. These values provide a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, DNB events in which the core limits are modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are also indirectly modeled in the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is a design radial peaking factor (nuclear enthalpy rise hot channel factor) used in the unit safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase by the value for $PF_{\Delta H}$ specified in the COLR for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other MODES (MODES 2 through 5) have significant margin to the DNBR limit, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these MODES.

BASES

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limits are not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limits may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be performed prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux - High to ≤ 55% RTP in accordance with Required Action A.1.2.2. Reducing RTP to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

BASES

ACTIONS (continued)

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are bounding and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a MODE in which the LCO requirements are not applicable. 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 regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

- NOTE -

An additional measurement uncertainty is to be applied if the number of measured thimbles for the moveable incore detector system is less than or equal to 37 but greater than or equal to 25. The additional uncertainty of (0.01)*[3-(T/12.5)] is added to 1.04, where T is the total number of measured thimbles. At least three measured thimbles per core quadrant are also required.

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

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

REFERENCES

1. Regulatory Guide 1.77, Rev. 0, May 1974.
2. 10 CFR 50, Appendix A, GDC 26.
3. 10 CFR 50.46.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the amount of axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

Relaxed Axial Offset Control (RAOC) is a calculational procedure that defines the allowed operational space of the AFD versus THERMAL POWER. The AFD limits are selected by considering a range of axial xenon distributions that may occur as a result of large variations of the AFD. Subsequently, power peaking factors and power distributions are examined to ensure that the loss of coolant accident (LOCA), loss of flow accident, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

The AFD is monitored on an automatic basis using the unit process computer, which has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels is outside its specified limits. If the AFD monitor is out of service, indicated AFD for each OPERABLE excore channel is manually monitored in accordance with the requirements specified in the Licensing Requirements Manual (Ref. 1).

Although the RAOC defines limits that must be met to satisfy safety analyses, typically an operating scheme, Constant Axial Offset Control (CAOC) is used to control axial power distribution in day to day operation (Ref. 2). CAOC requires that the AFD be controlled within a narrow tolerance band around a burnup dependent target to minimize the variation of axial peaking factors and axial xenon distribution during unit maneuvers.

The CAOC operating space is typically smaller and lies within the RAOC operating space. Control within the CAOC operating space constrains the variation of axial xenon distributions and axial power distributions. RAOC calculations assume a wide range of xenon distributions and then confirm that the resulting power distributions satisfy the requirements of the accident analyses.

BASES

APPLICABLE SAFETY ANALYSES

The AFD is a measure of the axial power distribution skewing to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution, and, to a lesser extent, reactor coolant temperature and boron concentration.

The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The RAOC methodology (Ref. 3) establishes a xenon distribution library with tentatively wide AFD limits. One dimensional axial power distribution calculations are then performed to demonstrate that normal operation power shapes are acceptable for the LOCA and loss of flow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also restrict the range of power distributions that are used as initial conditions in the analyses of Condition 2, 3, or 4 events. This ensures that the fuel cladding integrity is maintained for these postulated accidents. The most limiting Condition 4 event with respect to the AFD limits is the LOCA. The most limiting Condition 3 event with respect to the AFD limits is the loss of flow accident. The most limiting Condition 2 events with respect to the AFD limits include the uncontrolled RCCA bank withdrawal at power, dropped RCCA, and boron dilution accidents. Condition 2 accidents simulated to begin from within the AFD limits are used to confirm the adequacy of the Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator through the manual operation of the control banks or automatic motion of control banks. The automatic motion of the control banks is in response to temperature deviations resulting from manual operation of the Chemical and Volume Control System to change boron concentration or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 4). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detectors in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

BASES

LCO (continued)

The AFD limits are provided in the COLR. Figure B 3.2.3-1 shows typical RAOC AFD limits. The AFD limits for RAOC do not depend on the target flux difference. However, the target flux difference may be used to minimize changes in the axial power distribution.

Violating this LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its specified limits.

The LCO is modified by a Note which states that AFD shall be considered outside its limit when two or more OPERABLE excore channels indicate AFD to be outside its limit.

APPLICABILITY

The AFD requirements are applicable in MODE 1 greater than or equal to 50% RTP when the combination of THERMAL POWER and core peaking factors are of primary importance in safety analysis.

For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.

ACTIONS

A.1

As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

This Surveillance verifies that the AFD, as indicated by the NIS excore channel, is within its specified limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. Licensing Requirements Manual (LRM).

2. WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974.

3. WCAP-10216-P-A, Rev. 1A, "Relaxation of Constant Axial Offset Control: F_Q Surveillance Technical Specification," February 1994.

4. UFSAR, Chapter 7 (Unit 1) and UFSAR Chapter 4 (Unit 2).

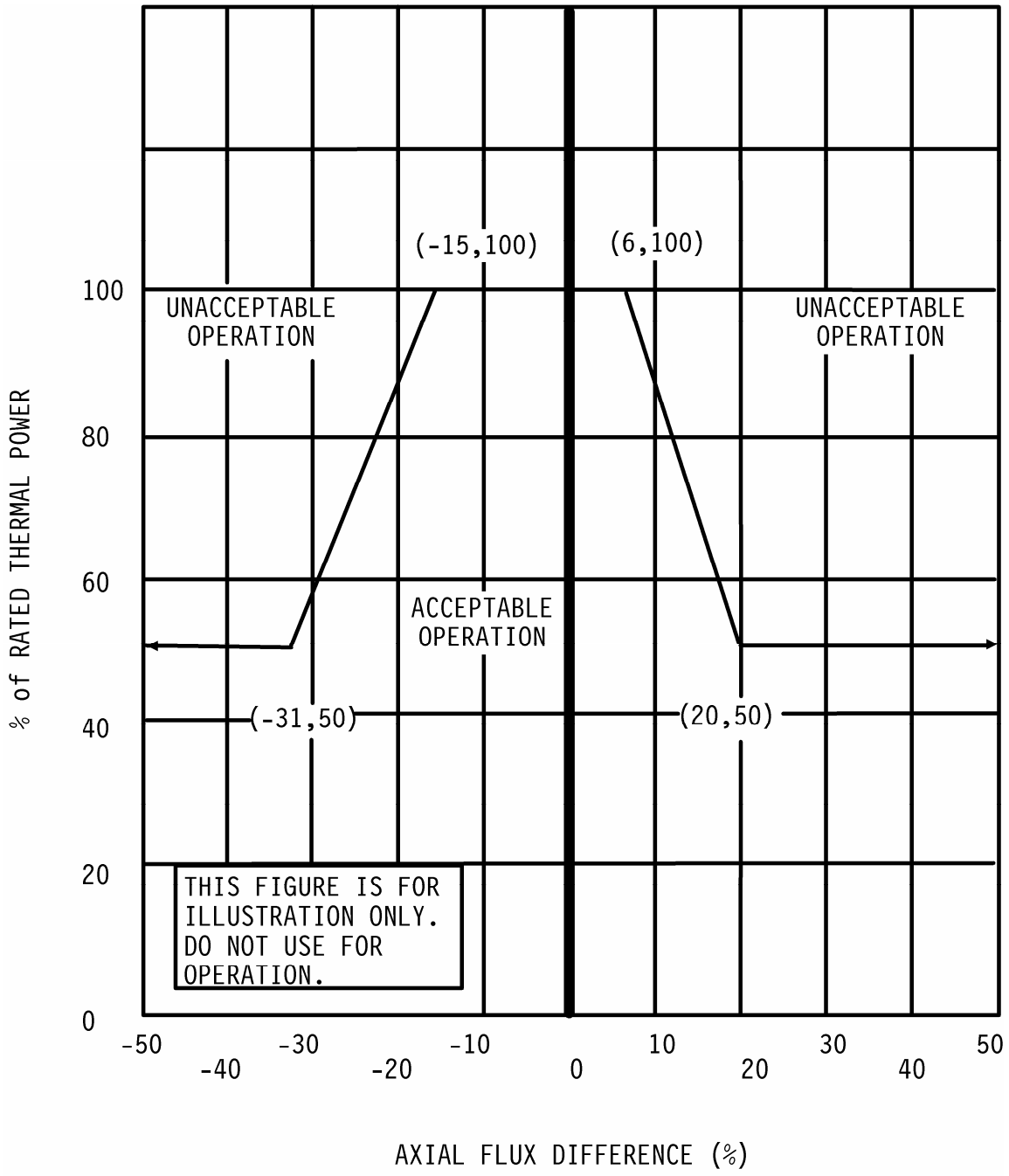

Figure B 3.2.3-1 (page 1 of 1)
AXIAL FLUX DIFFERENCE Acceptable Operation Limits
as a Function of RATED THERMAL POWER

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Rod Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large or small break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1),

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 2), and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

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

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and ($F^N_{\Delta H}$) is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of ≥ 3% from RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of QPTR. Increases in QPTR would require power reduction within 2 hours of QPTR determination, if necessary to comply with the decreased maximum allowable power level. Decreases in QPTR would allow increasing the maximum allowable power level and increasing power up to this revised limit.

BASES

ACTIONS (continued)

A.2

After completion of Required Action A.1, the QPTR alarm may still be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F_{\Delta H}^N$ and $F_Q(Z)$ within the Completion Time of 24 hours after achieving equilibrium conditions from a Thermal Power reduction per Required Action A.1 ensures that these primary indicators of power distribution are within their respective limits. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to support flux mapping. A Completion Time of 24 hours after achieving equilibrium conditions from Thermal Power reduction per Required Action A.1 takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map. If these peaking factors are not within their limits, the applicable Required Actions provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F_{\Delta H}^N$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F_{\Delta H}^N$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best

BASES

ACTIONS (continued)

characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limits prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished in such a manner that the indicated QPTR following normalization is near 1.00. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by two Notes. Note 1 states that the QPTR is not restored to within limits until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limits, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing flux mapping to verify peaking factors, per Required Action A.6. These Notes are intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the flux tilt is restored to within limits (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are within their specified limits within 24 hours of achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach equilibrium conditions at RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

BASES

ACTIONS (continued)

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been normalized to restore QPTR to within limits (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limits and the core returned to power.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is ≤ 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

For those causes of power tilt that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 12 hours after the input from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is > 75% RTP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. The incore detector monitoring is performed with a full incore flux map or two sets of four thimble locations with quarter core symmetry. The two sets of four symmetric thimbles is a set of eight unique detector locations. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, and N-8.

The symmetric thimble flux map can be used to generate symmetric thimble "tilt." This can be compared to a reference symmetric thimble tilt, from the most recent full core flux map, to generate an incore QPTR. Therefore, incore monitoring of QPTR can be used to confirm that QPTR is within limits.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous flux maps either using the symmetric thimbles as described above or a complete flux map. Nominally, quadrant tilt from the Surveillance should be within 2% of the tilt shown by the most recent flux map data.

REFERENCES

1. 10 CFR 50.46.
2. Regulatory Guide 1.77, Rev 0, May 1974.
3. 10 CFR 50, Appendix A, GDC 26.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying 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 Analytical 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 when reaching the Analytical 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 Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action may actually occur.

The nominal trip setpoint is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)."

For each automatic protective device there is a setting beyond which the device would not be able to perform its function due, for example, to greater than expected drift. The value of this setting is specified in the Technical Specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value.

BASES

BACKGROUND (continued)

The Allowable Value specified in Table 3.3.1-1 serves as the OPERABILITY limit such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value. 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 the assumptions stated in the BVPS Unit 1 and Unit 2 setpoint methodology for protection systems (Ref. 1). 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.

In addition to the channel OPERABILITY guidance discussed above, the CHANNEL OPERATIONAL TEST (COT) and CHANNEL CALIBRATION Surveillance Requirements (SRs) specified on Table 3.3.1-1 for certain RTS Functions are modified by Notes (k) and (l) that specify additional Technical Specification requirements. The applicable Notes are specified directly on Table 3.3.1-1 next to the numerical SR designations for the affected RTS Functions. The additional Technical Specification requirements for these RTS Functions include OPERABILITY evaluations for setpoints found outside the as-found acceptance criteria band and the requirement to reset the setpoint to within the as-left tolerance of the nominal trip setpoint or a value that is more conservative than the nominal trip setpoint or declare the affected channel inoperable. These additional Technical Specification requirements are only applicable to the RTS Functions with the Notes modifying their COT and CHANNEL CALIBRATION SR numbers on Table 3.3.1-1.

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value,

2. Fuel centerline melt shall not occur, and

3. The RCS pressure of 2748.5 psia shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50.67 limits during AOOs.

BASES

BACKGROUND (continued)

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within the 10 CFR 50.67 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RTS instrumentation is segmented into four distinct but interconnected modules as described in UFSAR, Chapter 7 (Ref. 2), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured,

2. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: provides signal conditioning, trip device setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications,

3. Solid State Protection System (SSPS), including input, logic, and output bays: initiates proper unit shutdown and/or ESF actuation in accordance with the defined logic, which is based on the trip device outputs from the signal process control and protection system, and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

<u>Field Transmitters or Sensors</u>

To meet the design demands for redundancy and reliability, more than one, and in some cases as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the nominal trip setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor is determined by either "as-found" calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

BASES

BACKGROUND (continued)

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. The safety analyses and associated RTS Functions are discussed in UFSAR Chapter 14 (Unit 1) and UFSAR Chapter 15 (Unit 2) (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a trip device is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 4). However, exceptions to the requirement for four channels are part of the design and licensing basis of the RTS (e.g., steam generator level instrumentation). The actual number of channels required for each unit parameter is specified in Technical Specification Table 3.3.1-1.

Two logic trains are required to ensure no single random failure of a logic train will disable the RTS. The logic trains are designed such that testing required while the reactor is at power may be accomplished without causing trip. Provisions to allow removing logic trains from service during maintenance are unnecessary because of the logic system's designed reliability.

BASES

BACKGROUND (continued)

Allowable Values, RTS Setpoints, and LSSS

The nominal trip setpoints used in trip devices are based on the analytical limits stated in Reference 1. The selection of these nominal trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. The nominal trip setpoints account for calibration tolerances, instrument uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5). The nominal trip setpoints are specified in the Licensing Requirements Manual (LRM). The Allowable Values specified in the Technical Specifications are determined by adding (or subtracting) the calibration accuracy of the trip device to the nominal trip setpoint in the non-conservative direction (i.e., toward or closer to the safety analysis limit) for the application. The Allowable Values remain conservative with respect to the analytical limits. For those channels that provide trip actuation via a bistable in the process racks, the calibration accuracy is defined by the rack calibration accuracy term. For a limited number of channels that provide trip actuation without being processed via the process racks (e.g., undervoltage relay or turbine trip channels) the Allowable Value is defined by device drift or repeatability (Ref. 1). The application of the calibration accuracy term (or device drift as applicable) to each RTS setpoint results in a "calibration tolerance band." Thus, the trip setpoint value is considered a "nominal" value (i.e., expressed as a value with a calibration tolerance) for the purposes of the COT and CHANNEL CALIBRATION. The calibration tolerance band for each RTS setpoint is specified in plant procedures. A detailed description of the methodology used to calculate the Allowable Values and nominal trip setpoints, including their explicit uncertainties, is provided in Reference 1 which incorporates all of the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the determination of each nominal trip setpoint and corresponding Allowable Value. The nominal trip setpoint entered into the trip device is more conservative than that specified by the Allowable Value to account for measurement errors detectable by the COT. The Allowable Value serves as the Technical Specification OPERABILITY limit. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the channel is considered OPERABLE. As discussed earlier, for certain RTS Functions, the COT and CHANNEL CALIBRATION SR numbers specified on Table 3.3.1-1 are modified by Notes that impose additional Technical Specification requirements for channel OPERABILITY.

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BACKGROUND (continued)

The nominal trip setpoint is the value at which the trip device is set and is the expected value to be achieved during calibration. The nominal trip setpoint value ensures the LSSS and the safety analysis limits are met for surveillance interval selected when a channel is adjusted to be within the calibration tolerance. Any trip device with a nominal trip setpoint is considered to be properly adjusted when the "as left" setpoint value is within the calibration tolerance.

The nominal trip setpoint is based on the calculated total loop uncertainty per the plant specific methodology documented in the Licensing Requirements Manual. The setpoint methodology, used to derive the nominal trip setpoints, is based upon combining all of the uncertainties in the channels. Inherent in the determination of the nominal trip setpoints are the magnitudes of these channel uncertainties. Sensors and other instrumentation utilized in these channels should be capable of operating within the allowances of these uncertainty magnitudes. Occasional drift in excess of the allowance may be determined to be acceptable based on the other device performance characteristics. Device drift in excess of the allowance that is more than occasional, may be indicative of more serious problems and would warrant further investigation.

Operable RTS Functions with setpoints maintained within the Allowable Values specified in the Technical Specifications ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed).

For most RTS Functions the Allowable Value specified on Table 3.3.1-1 is the LSSS required by 10 CFR 50.36. However, for certain RTS Functions, the COT and CHANNEL CALIBRATION SR numbers specified on Table 3.3.1-1 are modified by Notes (k) and (l) that impose additional Technical Specification Requirements for channel OPERABILITY and change the LSSS for the affected Functions. For each RTS Function in Table 3.3.1-1 with Notes modifying the required COT and CHANNEL CALIBRATION SR numbers, the nominal trip setpoint specified in the Licensing Requirements Manual is the LSSS.

This definition of the LSSS is consistent with the guidance issued to the industry through correspondence with Nuclear Energy Institute (NEI) (Reference NRC-NEI Letter dated September 7, 2005). The definition of LSSS values continues to be discussed between the industry and the NRC, and further modifications to these Bases will be implemented as guidance is provided.

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BACKGROUND (continued)

Table 3.3.1-1 Notes (k) and (l) are applicable to the COT and CHANNEL CALIBRATION SRs for specific instrument functions since changes to Allowable Values associated with these instrument functions were already under review by the NRC at the time the revised NRC setpoint criteria were documented and made available to the industry in an NRC letter to NEI. Changes to the remaining instrument functions may be pursued after guidance endorsed by both the NRC and NEI is issued.

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the nominal trip setpoint calibration tolerance specified in plant procedures. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of inputs from field contacts, control board switches and the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The SSPS performs the decision logic for actuating a reactor trip or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The input signals from field contacts, control board switches and bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

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BACKGROUND (continued)

Reactor Trip Switchgear

Two RTBs are connected in series in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening either of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power.

During normal operation the output from the SSPS is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the SSPS output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each RTB is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the SSPS. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism. The RTB bypass breakers are also equipped with a shunt trip device; however, manual actuation (local or remote) is required to energize this trip mechanism on the bypass breakers.

The decision logic matrix Functions are contained in the functional diagrams included in Reference 2. In addition to the reactor trip or ESF, these diagrams also illustrate the various "permissive interlocks" that are associated with unit conditions. Each train has a built in testing device that can automatically test the selected decision logic matrix Functions while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 3 takes credit for most RTS trip Functions. RTS trip Functions not explicitly credited in the accident analysis may be implicitly credited in the safety

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for conditions not explicitly analyzed and may be anticipatory in nature or serve as backups to RTS trip Functions that are explicitly credited in the accident analysis to provide defense in depth.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. A channel is OPERABLE provided the trip setpoint "as-found" value does not exceed its associated Allowable Value and provided the trip setpoint "as-left" value is adjusted to a value within the "as-left" calibration tolerance band of the nominal trip setpoint. A trip setpoint may be set more conservative than the nominal trip setpoint as necessary in response to plant conditions provided that the ± calibration tolerance band remains the same and the Allowable Value is administratively controlled accordingly in the conservative direction to meet the assumptions of the setpoint methodology. The conservative direction is established by the direction of the inequality applied to the Allowable Value. Failure of any instrument may render the affected channel(s) inoperable and reduce the reliability of the affected Functions.

In addition to the channel OPERABILITY guidance discussed above, the COT and CHANNEL CALIBRATION SRs specified on Table 3.3.3-1 for certain RTS Functions are modified by Notes (k) and (l) that specify additional Technical Specification requirements. The applicable Notes are specified directly on Table 3.3.1-1 next to the numerical SR designations for the affected RTS Functions. The additional Technical Specification requirements for these RTS Functions include OPERABILITY evaluations for setpoints found outside the as-found acceptance criteria band and the requirement to reset the setpoint to within the as-left tolerance of the nominal trip setpoint or a value that is more conservative than the nominal trip setpoint or declare the affected channel inoperable. These additional Technical Specification requirements are only applicable to the RTS Functions with the Notes modifying their COT and CHANNEL CALIBRATION SR numbers on Table 3.3.1-1.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic Function, and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration may be required when one RTS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In this case, the RTS will still provide protection,

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

even with random failure of one of the other three protection channels. Three OPERABLE instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. However, exceptions to these requirements are part of the current licensing and design basis (e.g., in the steam generator level instrumentation a median selector switch is utilized to provide functional separation between the protection and control systems instead of a fourth level instrument channel). The specific exceptions to the above general philosophy are discussed below.

Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip

   The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip switches in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. The Manual Reactor Trip feature is not credited by any safety analyses. It is used by the reactor operator to manually shut down the reactor.

   The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip switch. Each channel activates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if one or more shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core, or all of the rods are inserted, there is no need

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

to be able to trip the reactor. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn, except for specific activities such as drag testing performed under administrative controls, and the CRDMs are typically disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. One NIS power range detector provides input to the Rod Control System and (for Unit 2 only) the Steam Generator (SG) Water Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. As such, the power range instrument channels are combined in a two-out-of-four trip logic. Note that this Function also provides a signal to prevent automatic (for Unit 2) and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. Power Range Neutron Flux - High

The Power Range Neutron Flux - High trip Function ensures that protection is provided, from all power levels, against a fast positive reactivity excursion that could potentially lead to a violation of the safety analysis limit DNBR during power operation. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux - High channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux - High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux - High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Power Range Neutron Flux - Low

The LCO requirement for the Power Range Neutron Flux - Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux - Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2 with $k_{eff} \geq 1.0$, MODE 2 with $k_{eff} < 1.0$, and all RCS cold leg temperatures ≥ 500°F, and RCS boron concentration ≤ the ARO critical boron concentration when the Rod Control System is capable of rod withdrawal, or one or more rods not fully inserted, and in MODE 3 with all RCS cold leg temperatures ≥ 500°F, and the RCS boron concentration is ≤ the ARO critical boron concentration when the Rod Control System is capable of rod withdrawal, or one or more rods are not fully inserted, the Power Range Neutron Flux - Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than the P-10 setpoint specified in the LRM. This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux - High trip Function.

In MODE 3, with an RCS cold leg temperature < 500°F, 4, 5, or 6, the Power Range Neutron Flux - Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, with an RCS cold leg temperature < 500°F, 4, 5, or 6.

3. Power Range Neutron Flux - High Positive Rate

The Power Range Neutron Flux Rate trip uses the same channels as discussed for Function 2 above.

The Power Range Neutron Flux - High Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux that are characteristic of an RCCA drive rod housing rupture and the accompanying ejection of the RCCA. Although this

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Function is not explicitly credited in the safety analyses as a primary reactor trip, this Function compliments the Power Range Neutron Flux - High and Low Setpoint trip Functions to ensure that the applicable acceptance criteria are met for a rod ejection from the power range.

The LCO requires all four of the Power Range Neutron Flux - High Positive Rate channels to be OPERABLE.

In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a rod ejection accident (REA), the Power Range Neutron Flux - High Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux - High Positive Rate trip Function does not have to be OPERABLE because other RTS trip Functions and administrative controls will provide protection against positive reactivity additions. Also, since only the shutdown banks are fully withdrawn in MODE 3 for reactor startup, the remaining complement of control bank worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn, except for specific activities such as drag testing performed under administrative controls, and the SDM is increased during refueling operations. For the majority of the time the plant is in MODE 6 the reactor vessel head is also removed or the closure bolts are detensioned preventing any pressure buildup. In addition, the NIS power range detectors cannot detect neutron levels present in this MODE.

4. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux - Low Setpoint trip Function. The Intermediate Range Neutron Flux trip is not credited in the safety analyses as a primary reactor trip. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires two channels of Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. The trip Function is accomplished by a one-out-of-two trip logic.

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

In MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux - High Setpoint trip and the Power Range Neutron Flux - High Positive Rate trip provide core protection for a rod withdrawal accident. In MODE 2 below the P-6 setpoint, the Source Range Neutron Flux Trip provides the primary core protection for reactivity accidents. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE. In MODE 3 with the RCS temperature ≥ 500°F, the Power Range Neutron Flux - Low trip Function provides the protection for an uncontrolled RCCA bank withdrawal event from low power or subcritical conditions. In MODE 3 with any RCS cold leg temperature < 500°F, and in MODES 4 and 5, LCO 3.1.10, "RCS Boron Limitations < 500°F," requires that the RCS boron concentration be greater than the all-rods-out (ARO) critical boron concentration to ensure that sufficient SHUTDOWN MARGIN is available if an uncontrolled RCCA bank withdrawal event were to occur. In MODE 6, all rods are fully inserted, except for specific activities such as drag testing performed under administrative controls, and the core has an increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

5. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux - Low trip Function. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3 (with any RCS cold leg temperature < 500°F), 4, and 5 when rods are capable of withdrawal or one or more rods are not fully inserted.

In MODE 3 with the RCS temperature ≥ 500°F, the Power Range Neutron Flux - Low trip Function provides protection for an uncontrolled RCCA bank withdrawal or control rod ejection event from low power or subcritical conditions.

In MODE 3 with any RCS cold leg temperature < 500°F, and in MODES 4 and 5, LCO 3.1.10 requires that the RCS be borated to greater than the ARO critical boron concentration to ensure that sufficient SHUTDOWN MARGIN is available to mitigate an uncontrolled RCCA bank withdrawal event or control rod ejection event. Therefore, the safety analyses do not take explicit credit for the Source Range Neutron Flux trip Function as a primary trip to mitigate an uncontrolled RCCA bank withdrawal or control rod ejection event. LCO 3.1.10 ensures that sufficient SHUTDOWN MARGIN is available if an uncontrolled RCCA bank withdrawal or control rod ejection event were to occur.

The reliance on the boron limitation of LCO 3.1.10 when the RCS temperature is below 500°F in MODES 3, 4, and 5 and the Power Range Neutron Flux - Low trip Function when the RCS temperature is ≥ 500°F in MODE 3, to address an uncontrolled RCCA bank withdrawal accident, is consistent with the guidance of Westinghouse Nuclear Safety Advisory Letter 00-016 (Ref. 6).

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution (during startup) and control rod ejection events. The trip Function is accomplished by a one-out-of-two trip logic.

Alternate source range neutron flux detectors may be used in place of the primary NIS source range neutron flux detectors as long as the required source range indication and trip functions are provided by the alternate detectors.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 2 below the P-6 setpoint and in MODES 3, 4, and 5 when there is a potential for an uncontrolled RCCA bank rod withdrawal accident, the Source Range Neutron Flux trip must be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux - Low trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized.

In MODES 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs of the Function to the RTS logic are not required OPERABLE. The requirements for the NIS source range detectors to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like a boron dilution are addressed in LCO 3.3.8 "Boron Dilution Detection Instrumentation," for MODE 3, 4, or 5 and LCO 3.9.2, "Nuclear Instrumentation," for MODE 6.

6. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the nominal trip setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature,
- pressurizer pressure - the nominal trip setpoint is varied to correct for changes in system pressure, and

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- axial power distribution - f(ΔI), the nominal trip setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the trip setpoint is reduced in accordance with Note 1 (Unit 1) and Note 3 (Unit 2) of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 (Unit 1) and Note 3 (Unit 2) in Table 3.3.1-1. Trip occurs if Overtemperature ΔT is indicated in two loops. The pressure and temperature signals are used for other control functions. The actuation logic can withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. In order to meet this requirement with three channels of T_{avg} and ΔT, functional separation between the protection and control systems is accomplished by the use of a median signal selector switch. Note that this Function also provides a signal to generate a turbine runback prior to reaching the trip setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires three channels of the Overtemperature ΔT trip Function to be OPERABLE. An OPERABLE hot leg channel consists of: 1) three RTDs per hot leg, or 2) two RTDs per hot leg with the failed RTD disconnected and the required bias applied. The trip Function is accomplished by a two-out-of-three trip logic. Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent a violation of the safety limit DNBR. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux - High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the nominal Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature, and

- rate of change of reactor coolant average temperature - including dynamic compensation for the delays between the core and the temperature measurement system.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 (Unit 1) and Note 4 (Unit 2) in Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. The temperature signals are used for other control functions. The actuation logic can withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. In order to meet this requirement with three channels of T_{avg} and ΔT, functional separation between the protection and control systems is accomplished by the use of a median signal selector switch. Note that this Function also provides a signal to generate a turbine runback prior to reaching the nominal Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires three channels of the Overpower ΔT trip Function to be OPERABLE. An OPERABLE hot leg channel consists of: 1) three RTDs per hot leg, or 2) two RTDs per hot leg with the failed RTD disconnected and the required bias applied. Note that the Overpower ΔT trip Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions. The trip Function is accomplished by a two-out-of-three trip logic.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

8. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure - High and - Low trips and the Overtemperature ΔT trip. A separate control channel provides input to the Pressurizer Pressure Control System. Therefore, the actuation logic can withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

a. Pressurizer Pressure - Low

The Pressurizer Pressure - Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires three channels of Pressurizer Pressure - Low to be OPERABLE. The trip Function is accomplished by a two-out-of-three trip logic.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure - Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine First Stage pressure greater than P-13). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure - High

The Pressurizer Pressure - High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires three channels of the Pressurizer Pressure - High to be OPERABLE. The trip Function is accomplished by a two-out-of-three trip logic.

The Pressurizer Pressure - High LSSS is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding an unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure - High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure - High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, the Overpressure Protection System (OPPS) provides overpressure protection in MODE 4 and below when any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR.

9. Pressurizer Water Level - High

The Pressurizer Water Level - High trip Allowable Value in Table 3.3.1-1 is specified in % of instrument span. The Pressurizer Water Level - High trip Function provides a backup signal for the Pressurizer Pressure - High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The Pressurizer Water Level - High trip Function is not credited in any safety analyses as the primary reactor trip. The LCO requires three channels of Pressurizer Water Level - High to be OPERABLE. The trip Function is accomplished by a two-out-of-three trip logic. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before a reactor high pressure trip.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level - High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

10. Reactor Coolant Flow - Low

The Reactor Coolant Flow - Low trip Allowable Value in Table 3.3.1-1 is specified in % of indicated loop flow. The Reactor Coolant Flow - Low trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, specified in the LRM, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow - Low channels per loop to be OPERABLE in MODE 1 above P-7. The trip Function is accomplished by a two-out-of-three trip logic in each loop.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core because of the higher power level. In MODE 1 below the P-8 setpoint and above the P-7 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip because of the lower power level and the greater margin to the design limit DNBR. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since there is insufficient heat production to generate DNB conditions.

11. Reactor Coolant Pump (RCP) Breaker Position

The RCP Breaker Position trip Function consists of one set of auxiliary contacts on each RCP breaker. The Function anticipates the Reactor Coolant Flow - Low trips to avoid RCS heatup that would occur before the low flow trip actuates. The RCP Breaker Position trip Function is not credited in any safety analyses as the primary reactor trip.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The RCP Breaker Position trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The position of each RCP breaker is monitored. Above the P-7 setpoint, a loss of flow in two or more loops will initiate a reactor trip. As such, the trip Function is accomplished by a two-out-of-three trip logic. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this Function because the RCS Flow - Low trip alone provides sufficient protection of the DNBR limit for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of two RCPs.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-7 setpoint, the RCP Breaker Position trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled.

12. Undervoltage Reactor Coolant Pumps

The Undervoltage RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. As such, the trip Function is accomplished by a two-out-of-three trip logic. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCP channels to prevent reactor trips due to momentary electrical power transients. The Undervoltage RCP Bus trip Function is not credited in any safety analyses as the primary reactor trip.

The LCO requires three Undervoltage RCP channels one per bus to be OPERABLE.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled. This Function uses the same relays as the ESFAS Function, "Undervoltage Reactor Coolant Pump (RCP)" start of the auxiliary feedwater (AFW) pumps.

13. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip.

The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. Above the P-7 setpoint, a loss of frequency detected on two or more RCP buses will initiate a reactor trip. As such, the trip Function is accomplished by a two-out-of-three trip logic. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Underfrequency RCPs channels to prevent reactor trips due to momentary electrical power transients. The Underfrequency RCP Bus trip Function is not credited in any safety analyses as the primary reactor trip.

The LCO requires three Underfrequency RCPs channels, one per bus, to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Underfrequency RCPs trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

14. Steam Generator Water Level - Low Low

The SG Water level - Low Low trip Function Allowable Value in Table 3.3.1-1 is specified in % of narrow range instrument span for each SG. The SG Water Level - Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The level transmitters provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Functional separation between the protection and control systems is accomplished by the use of a median selector switch. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level.

The LCO requires three channels of SG Water Level - Low Low per SG to be OPERABLE. The trip Function is accomplished by a two-out-of-three trip logic on any SG.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level - Low Low trip must be OPERABLE. In MODE 3, 4, 5, or 6, the SG Water Level - Low Low Function does not have to be OPERABLE because the reactor is not operating or even critical.

15. Turbine Trip

a. Turbine Trip - Low Fluid Oil Pressure

The Turbine Trip - Low Fluid Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-9 setpoint, specified in the LRM, will not actuate a reactor trip. Three pressure switches monitor the Unit 1 Auto Stop oil pressure and three pressure switches monitor the Unit 2 Emergency Trip Header pressure. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function and RCS integrity is ensured by the pressurizer safety valves. The Turbine Trip Function is not credited in any safety analyses as the primary reactor trip.

The LCO requires three channels of Turbine Trip - Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-9.

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip - Low Fluid Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip - Turbine Stop Valve Closure

The Turbine Trip - Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level above the P-9 setpoint specified in the LRM. Below the P-9 setpoint, the Turbine Trip Function will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip - Low Fluid Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RTS. If all four limit switches indicate that the stop valves are all closed, a reactor trip is initiated. The Turbine Trip Function is not credited in any safety analyses as the primary reactor trip.

The LSSS for this Function is set to assure channel trip occurs when the associated stop valve is completely closed. The setpoint for the Turbine Trip - Turbine Stop Valve Closure channels is the only RTS setpoint that is not a nominal trip setpoint with a calibration tolerance. The setpoint for this Function contains an inequality similar to the Allowable Value in

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the Technical Specification. The trip setpoint is adjusted to be consistent with the trip setpoint value specified in the LRM in lieu of adjusting the setpoint to be within an established calibration tolerance band.

The LCO requires four Turbine Trip - Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-9. All four channels must trip to cause reactor trip.

Below the P-9 setpoint, a load rejection can be accommodated by the Steam Dump System. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip - Stop Valve Closure trip Function does not need to be OPERABLE.

16. Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates SI. Typically, transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. The large break LOCA analysis does not rely upon rod insertion and credits the voiding of the core to shutdown the reactor. Therefore, a reactor trip is initiated every time an SI signal is present.

As the requirements for the ESFAS instrument channels, including actuation logic and Allowable Values are specified separately in LCO 3.3.2, there are no trip setpoint and Allowable Values applicable to this RTS Function. The SI Input is provided by the ESFAS logic. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

17. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed, and

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine First Stage Pressure, P-13 interlock. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure - Low,
- Pressurizer Water Level - High,
- Reactor Coolant Flow - Low (low flow in two or more RCS loops),
- RCPs Breaker Open (two or more RCPs),
- Undervoltage RCPs (two or more RCP buses), and
- Underfrequency RCPs (two or more RCP buses).

These reactor trips are only required when operating above the P-7 setpoint (as specified in the LRM for the P-10 and P-13 inputs to P-7). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure - Low,
- Pressurizer Water Level - High,
- Reactor Coolant Flow - Low (low flow in two or more RCS loops),
- RCP Breaker Position (two or more RCPs),
- Undervoltage RCPs (two or more RCP buses), and
- Underfrequency RCPs (two or more RCP buses).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Trip Setpoint and Allowable Value are not applicable to the P-7 interlock because it is a logic Function and thus has no parameter with which to associate an LSSS.

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below the P-7 setpoint, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock setpoint is specified in the LRM and is actuated by two-out-of-four NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow - Low (Single Loop) reactor trip on low flow in one or more RCS loops on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than the P-8 setpoint. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock setpoint is specified in the LRM and is actuated by two-out-of-four NIS power range detectors. The LCO requirement for this Function ensures that the Turbine Trip - Low Fluid Oil Pressure (Auto Stop (Unit 1) and Emergency Trip Header (Unit 2)) and Turbine

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Trip - Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the capacity of the Steam Dump System. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1.

In MODE 1, a turbine trip could cause a load rejection beyond the capacity of the Steam Dump System, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacity of the Steam Dump System.

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock setpoint is specified in the LRM and is actuated by two-out-of-four NIS power range detectors. If power level falls below the P-10 setpoint on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. Note that blocking the reactor trip also blocks the signal to prevent automatic (for Unit 2) and manual rod withdrawal,
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux - Low reactor trip,
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detectors,
- the P-10 interlock provides one of the two inputs to the P-7 interlock, and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux - Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux - Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

f. Turbine First Stage Pressure, P-13

The turbine power (P-13) Allowable Value in Table 3.3.1-1 is specified in % RTP turbine first stage pressure equivalent. The Turbine First Stage Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than the P-13 setpoint specified in the LRM. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine First Stage Pressure, P-13 interlock to be OPERABLE in MODE 1.

The Turbine First Stage Pressure, P-13 interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

18. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of an OPERABLE RTB. When an RTB bypass breaker is racked in and closed to bypass an RTB, the RTB is no longer capable of performing its safety function and the bypassed RTB is inoperable. The Action Condition for an inoperable RTB contains Notes that provide additional time for bypassing the RTB for surveillance testing and maintenance. A racked in and closed bypass breaker and the remaining operable RTB are actuated from the same train of RTS actuation logic.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Therefore, when bypassing an RTB, the RTB trip Function is no longer single failure proof and the time an RTB can be bypassed is limited in accordance with the applicable RTB Action Condition Note. In addition, the bypass breaker is required to be OPERABLE prior to being placed in service in accordance with SR 3.3.1.4. Two OPERABLE trains ensure no single random failure can disable the RTS trip capability.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 18 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

20. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 20) ensures that means are provided to automatically interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE trains ensures that random failure of a single logic train will not prevent reactor trip.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

The RTS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1. When the required channels in Table 3.3.1-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or trip device is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the SSPS for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

BASES

ACTIONS (continued)

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C would apply to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

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

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted:

Manual Reactor Trip,

RTBs,

RTB Undervoltage and Shunt Trip Mechanisms, and

Automatic Trip Logic.

This action addresses the train orientation of the SSPS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

BASES

ACTIONS (continued)

D.1.1, D.1.2, D.2.1, D.2.2, and D.3

Condition D applies to the Power Range Neutron Flux - High Function.

One NIS power range detector provides input to the Rod Control System and (for Unit 2 only) the SG Water Level Control System and, therefore, a two-out-of-four trip logic is used. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-14333-P-A, Rev. 1 (Reference 7).

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 78 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 72 hours and the QPTR monitored once every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels ≥ 75% RTP. The 12 hour Frequency is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight hours are allowed to place the plant in MODE 3. The 78 hours Completion Time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction required by Required Action D.3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 12 hour time limit is justified in Reference 7.

BASES

ACTIONS (continued)

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors once per 12 hours may not be necessary.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux - Low,
- Overtemperature ΔT,
- Overpower ΔT,
- Power Range Neutron Flux - High Positive Rate,
- Pressurizer Pressure - High, and
- SG Water Level - Low Low.

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 7.

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 7.

BASES

ACTIONS (continued)

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

BASES

ACTIONS (continued)

Required Action G.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management, temperature control or plant cooldown to exit the MODE of Applicability and place the plant in a safer condition) are not precluded by this Action, provided they are accounted for in the calculated SDM.

H.1

Condition H applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint, and performing a reactor startup. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

Required Action H.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management, temperature control or plant cooldown to exit the MODE of Applicability and place the plant in a safer condition) are not precluded by this Action, provided they are accounted for in the calculated SDM.

I.1

Condition I applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition.

J.1, J.2.1, and J.2.2

Condition J applies to one inoperable source range channel in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to

BASES

ACTIONS (continued)

an OPERABLE status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour.

K.1 and K.2

Condition K applies to the following reactor trip Functions:

- Pressurizer Pressure - Low,
- Pressurizer Water Level - High,
- Reactor Coolant Flow - Low,
- RCP Breaker Position,
- Undervoltage RCPs, and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. For the Pressurizer Pressure - Low, Pressurizer Water Level - High, Undervoltage RCPs, Underfrequency RCPs, and RCP Breaker Position trip Functions, placing the channel in the tripped condition when above the P-7 setpoint results in a partial trip condition requiring only one additional channel to initiate a reactor trip. For the Reactor Coolant Flow - Low (Two Loop) trip Function, placing the channel in the tripped condition when above the P-8 setpoint results in a partial trip condition in one loop requiring only one additional channel in the same loop to initiate a low flow signal for that loop. For the latter trip Function, two tripped channels in two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. The pressurizer pressure low Function and RCS flow related Functions do not have to be OPERABLE below the P-7 setpoint because there is insufficient heat production to generate DNB conditions below the P-7 setpoint. The pressurizer water level Function is not required OPERABLE below the P-7 setpoint, because transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 7. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

BASES

ACTIONS (continued)

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 7.

L.1 and L.2

Condition L applies to Turbine Trip on Low Fluid Oil Pressure or on Turbine Stop Valve Closure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours. If placed in the tripped condition, this results in a partial trip condition. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 7 for Turbine Trip on Low Fluid Oil Pressure. Reference 8 justifies the 72 hour Completion Time allowed to place an inoperable channel in the tripped condition for Turbine Trip on Turbine Stop Valve Closure.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 7 for Turbine Trip on Low Fluid Oil Pressure, and Reference 8 for Turbine Trip on Turbine Stop Valve Closure.

M.1 and M.2

Condition M applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status (Required Action M.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours (Required Action M.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The 24 hours allowed to restore the inoperable RTS Automatic Trip Logic Train to OPERABLE status is justified in Reference 7.

BASES

ACTIONS (continued)

The Completion Time of 6 hours (Required Action M.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements for WCAP-14333-P-A, Rev. 1 (Reference 7), Tier 2 insights must be included in the decision making process before removing an RTS logic train from service and implementing the extended (risk-informed) Completion Time for an RTS logic train approved in Reference 10. These "Tier 2 restrictions" are considered to be necessary to avoid risk significant plant configurations during the time an RTS logic train is inoperable.

Entry into Condition M for an inoperable RTS logic train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition M may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition M entry. In addition, it is possible that equipment failure may occur after the RTS logic train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures in place to address the requirements of 10 CFR 50.65(a)(4) require assessment of the emergent condition with appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable logic train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition M when an RTS logic train is inoperable:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable.

BASES

ACTIONS (continued)

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained. Note that Technical Specification 3.5.2, ECCS Operating, ensures that this restriction is met. Therefore, this restriction does not have to be implemented by a separate procedure or program.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.

- Activities on electrical systems (AC and DC power) and cooling systems (service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

N.1 and N.2

Condition N applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24 hour Completion Time is justified in Reference 9. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in ACTION C entry while RTB(s) are inoperable.

The Required Actions have been modified by a Note. The Note allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The 4 hours allowed to bypass a train is justified in Reference 9.

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements in WCAP-15376-P-A, Rev. 1 (Reference 9), Tier 2 insights must be included in the decision making process before removing an RTB train from service and implementing the extended (risk-informed) Completion Time for an RTB train approved in Reference 10. These "Tier 2 restrictions" are considered to be necessary to avoid risk significant plant configurations during the time an RTB train is inoperable.

BASES

ACTIONS (continued)

Entry into Condition N for an inoperable RTB train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition N may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition N entry. In addition, it is possible that equipment failure may occur after the RTB train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures in place to address the requirements of 10 CFR 50.65(a)(4) require assessment of the emergent condition with appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable RTB train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition N when an RTB train is inoperable:

- The probability of failing to trip the reactor on demand will increase when a RTB is removed from service; therefore, systems designed for mitigating an ATWS event should be maintained available. RCS pressure relief (pressurizer PORVs and safety valves), auxiliary feedwater flow (for RCS heat removal), AMSAC, and turbine trip are important to ATWS mitigation. Therefore, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a RTB is inoperable.

- Due to the increased dependence on the available reactor trip train when one logic train is unavailable, activities that degrade other components of the RTS, including master relays or slave relays, and activities that cause analog channels to be unavailable, should not be scheduled when a logic train is inoperable.

- Activities on electrical systems (AC and DC power) that support the systems or functions listed in the first two bullets should not be scheduled when a RTB is inoperable.

BASES

ACTIONS (continued)

O.1 and O.2

Condition O applies to the P-6 and P-10 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The interlock status may be verified by observation of the associated permissive annunciator/status window(s). The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.

P.1 and P.2

Condition P applies to the P-7, P-8, P-9, and P-13 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The interlock status may be verified by observation of the associated permissive annunciator/status window(s). The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

Q.1 and Q.2

Condition Q applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C would apply to any inoperable RTB trip mechanism. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the

BASES

ACTIONS (continued)

time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance of the diverse features is 2 hours for the reasons stated under Condition N.

The Completion Time of 48 hours for Required Action Q.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

R.1

Condition R applies to one inoperable Power Range Neutron Flux - Low channel in MODE 2 with $k_{eff} < 1.0$, and all RCS cold leg temperatures ≥ 500°F, and RCS boron concentration ≤ the ARO critical boron concentration when the Rod Control System is capable of rod withdrawal, or one or more rods not fully inserted, and in MODE 3 with all RCS cold leg temperatures ≥ 500°F, and the RCS boron concentration is ≤ the ARO critical boron concentration when the Rod Control System is capable of rod withdrawal, or one or more rods are not fully inserted. The inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only a one-out-of-three logic for actuation of this reactor trip function. The 72 hours to place the inoperable channel in the tripped condition is justified in Reference 7.

The Required Action is modified by a Note. The Note allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 7.

S.1.1, S.1.2, and S.2

If the inoperable channel can not be placed in the tripped condition within the specified Completion Time, or if two or more channels are inoperable, action must be initiated immediately to fully insert all rods, and to make the rods incapable of rod withdrawal. This action will preclude an uncontrolled RCCA bank withdrawal accident from occurring.

Required Action S.2 provides an alternative to Required Actions S.1.1 and S.1.2. If the inoperable channel can not be placed in the tripped condition within the specified Completion Time, or if two or more channels are inoperable, action must be initiated to borate the RCS to > the ARO critical boron concentration. Borating the RCS to > the ARO critical boron concentration would provide sufficient SHUTDOWN MARGIN, if an uncontrolled RCCA bank withdrawal accident were to occur.

BASES

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of process protection supplies both trains of the RTS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

Performance of the CHANNEL CHECK ensures that 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 two 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 that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit 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.

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

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the power range channel output. If the calorimetric heat balance calculation results exceed the power range channel output by more than + 2% RTP, the power range is not declared inoperable, but must be adjusted. The power range channel output shall be adjusted consistent with the calorimetric heat balance calculation results if the calorimetric calculation exceed the power range channel output by more than + 2% RTP. If the power range channel output cannot be properly adjusted, the channel is declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

If the calorimetric is performed at part power (< 70% RTP when utilizing the venturis and < 30% RTP when utilizing the LEFM), adjusting the power range channel indication in the increasing power direction will assure a reactor trip below the safety analysis limit. Making no adjustment to the power range channel in the decreasing power direction due to a part power calorimetric assures a reactor trip consistent with the safety analyses. This allowance does not preclude making indicated power adjustments, if desired, when the calorimetric heat balance calculation is less than the power range channel output. To provide close agreement between indicated power and to preserve operating margin, the power range channels are normally adjusted when operating at or near full power during steady-state conditions. However, discretion must be exercised if the power range channel output is adjusted in the decreasing power direction due to a part power calorimetric (< 70% RTP when utilizing the venturis and < 30% RTP when utilizing the LEFM). This action may introduce a non-conservative bias at higher power levels that may result in a Power Range Neutron Flux - High reactor trip above the safety analysis limit. The cause of the potential non-conservative bias is the decreased accuracy of the calorimetric at reduced power conditions. The primary error contributor to the instrument uncertainty for a secondary side power calorimetric measurement is the feedwater flow measurement, which is typically a ΔP measurement across a feedwater venturi. While the measurement uncertainty remains constant in ΔP as power decreases, when translated into flow, the uncertainty increases as a square term. Thus a 1% flow error at 100% power can approach a 10% flow error at 30% RTP even though the ΔP error has not changed. This bias error is not present when using the leading edge flow meter (LEFM) to determine feedwater flow for performing the secondary side power calorimetric. However, when using the LEFM for performing the secondary side power calorimetric, the requirements of this SR assure a power range channel output and reactor trip function that are conservative with respect to the assumptions of the safety analyses described above. When using the LEFM for the performance of the secondary side power calorimetric, the Power Range Neutron Flux – High bistables may be reset to a nominal value specified in the LRM when confirmed based on a calorimetric performed ≥ 30% RTP.

An evaluation of extended operation at part power conditions would conclude that it is prudent to administratively adjust the setpoint of the Power Range Neutron Flux - High bistables to ≤ 85% RTP when: 1) the power range channel output is adjusted in the decreasing power direction due to a part power calorimetric below 70% RTP when utilizing the venturis and < 30% RTP when utilizing the LEFM; or 2) for a post refueling startup. The evaluation of extended operation at part power

BASES

SURVEILLANCE REQUIREMENTS (continued)

conditions would also conclude that the potential need to adjust the indication of the Power Range Neutron Flux in the decreasing power direction is quite small, primarily to address operation in the intermediate range about P-10 (nominally 10% RTP) to allow enabling of the Power Range Neutron Flux - Low setpoint and the Intermediate Range Neutron Flux reactor trips. If the high flux setpoints were adjusted to ≤ 85% AND the Power Range gain was adjusted in the decreasing direction, then before the Power Range Neutron Flux - High bistables are reset to a nominal value specified in the LRM, the power range channel adjustment must be confirmed based on a calorimetric performed at ≥ 70% RTP when utilizing the venturis and ≥ 30% RTP when utilizing the LEFM. The Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours are allowed for performing the first Surveillance after reaching 15% RTP. A power level of 15% RTP is chosen based on plant stability, i.e., automatic rod control capability and turbine generator synchronized to the grid.

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

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted (normalized) based on the incore surveillance data. The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to periodically verify the f(ΔI) input to the overtemperature ΔT Function. The Surveillance is assigned to both the Power Range Neutron Flux High and OTΔT RTS Functions to assure all 4 NIS channels are verified and adjusted, if necessary.

A Note clarifies that the Surveillance is required when reactor power is ≥ 50% RTP and that 7 days are allowed to perform the Surveillance and channel adjustment, if necessary, after reaching 50% RTP. A power level of ≥ 50% RTP is consistent with the requirements of SR 3.3.1.9. The performance of SR 3.3.1.9 may be used to satisfy the requirements of SR 3.3.1.3. SR 3.3.1.9 may be performed in lieu of SR 3.3.1.3 since SR 3.3.1.9 calibrates (i.e., requires adjustment of) the excore channels based on incore surveillance data and therefore envelopes the performance of SR 3.3.1.3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

For each operating cycle, the initial channel normalization is performed in accordance with SR 3.3.1.9. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT. This test shall verify OPERABILITY by actuation of the end devices. A successful test of any 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test for bypass breakers is included in SR 3.3.1.12. The bypass breaker test shall include a local manual shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

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

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function, including operation of the P-7 permissive which is a logic function only. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of any 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1 (excluding time constants which are verified during CHANNEL CALIBRATIONS).

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

For certain RTS Functions the required COT (SR 3.3.1.6 specified in Table 3.3.1-1) is modified by Notes (k) and (l). These Notes specify additional requirements for the affected instrument channels.

Note (k) specifies the following:

- If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service, and

- If the “as-found” instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

The evaluation of channel performance required by Note (k) involves an assessment to verify the channel will continue to behave in accordance with design basis assumptions, and to ensure confidence in the channel performance prior to returning the channel to service. In addition, if the "as found" trip setpoint value is non-conservative with respect to the

BASES

SURVEILLANCE REQUIREMENTS (continued)

Allowable Value, or is found to be outside of the two sided predefined acceptance criteria band on either side of the nominal trip setpoint, the affected channel will be evaluated under the corrective action program.

Note (l) specifies the following:

- The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the nominal trip setpoint, or a value that is more conservative than the nominal trip setpoint; otherwise, the channel shall be declared inoperable, and

- The nominal trip setpoint and the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in a document incorporated by reference into the Updated Final Safety Analysis Report.

For BVPS, the document containing the nominal trip setpoint, the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band is the LRM.

For the RTS Functions with a COT modified by Note (l), the Note requires that the instrument channel setpoint be reset to a value within the "as left" setpoint tolerance band on either side of the nominal trip setpoint or to a value that is more conservative than the nominal trip setpoint. The conservative direction is established by the direction of the inequality sign applied to the associated Allowable Value. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisfied in order to protect the safety analysis limits. If the channel can not be reset to a value within the required "as left" setpoint tolerance band on either side of the nominal trip setpoint, or to a value that is more conservative than the nominal trip setpoint (if required based on plant conditions) the channel is declared inoperable and the applicable ACTION is entered.

For the RTS Functions with a COT modified by Notes (k) and (l), the "as found" and "as left" setpoint data obtained during COTs or CHANNEL CALIBRATIONS are programmatically trended to demonstrate that the rack drift assumptions used in the plant setpoint methodology are valid. If the trending evaluation determines that a channel is performing inconsistent with the uncertainty allowances applicable to the periodic surveillance test being performed, the channel is evaluated under the corrective action program. If the channel is not capable of performing its specified safety function, it is declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6 is modified by a Note that provides a 12 hour delay in the requirement to perform this Surveillance for source range instrumentation after decreasing power below the P-6 interlock setpoint. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.6 is no longer required to be performed. If the unit is to be in MODE 2 below the P-6 setpoint or in MODE 3 with the RTBs closed for > 12 hours this Surveillance must be performed prior to 12 hours after decreasing power below the P-6 setpoint.

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

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT as described in SR 3.3.1.6, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within the Frequency specified in the Surveillance Frequency Control Program prior to reactor startup and 12 hours after reducing power below P-10. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the intermediate and power range low instrument channels. The Frequency of 12 hours after reducing power below P-10 (applicable to intermediate and power range low channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and 12 hours after reducing power below P-10. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 for more than 12 hours, then the testing required by this surveillance must be performed prior to the expiration of the time limit. Twelve hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10) for periods > 12 hours.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.8

SR 3.3.1.8 is the performance of a TADOT and the Surveillance Frequency is controlled under the Surveillance Frequency Control Program. A successful test of any 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.9

SR 3.3.1.9 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted (normalized), the channels are declared inoperable. This Surveillance is performed at BOL to normalize the excore channel f(ΔI) input to the overtemperature ΔT Function for each new operating cycle. The Surveillance is assigned to both the Power Range Neutron Flux High and OTΔT RTS Functions to assure all 4 NIS channels are initially normalized to the new core.

A Note modifies SR 3.3.1.9. The Note states that this Surveillance is required only if reactor power is ≥ 50% RTP and that 7 days are allowed for performing the Surveillance after reaching 50% RTP.

The Frequency of once per fuel cycle is adequate to establish the initial cycle-specific calibration of the excore channels. It is based on industry operating experience, considering instrument reliability and the performance of SR 3.3.1.3 every 31 EFPD which verifies the excore channels remain within the required calibration tolerance.

SR 3.3.1.10

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

BASES

SURVEILLANCE REQUIREMENTS (continued)

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detectors (RTD) sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

For certain RTS Functions the required CHANNEL CALIBRATION (SR 3.3.1.10 specified in Table 3.3.1-1) is modified by Notes (k) and (l). These Notes specify additional requirements for the affected instrument channels.

Note (k) specifies the following:

- If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service, and

- If the “as-found” instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

The evaluation of channel performance required by Note (k) involves an assessment to verify the channel will continue to behave in accordance with design basis assumptions, and to ensure confidence in the channel performance prior to returning the channel to service. In addition, if the "as found" trip setpoint value is non-conservative with respect to the Allowable Value, or is found to be outside of the two sided predefined acceptance criteria band on either side of the nominal trip setpoint, the affected channel will be evaluated under the corrective action program.

Note (l) specifies the following:

- The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the nominal trip setpoint, or a value that is more conservative than the nominal trip setpoint; otherwise, the channel shall be declared inoperable, and

BASES

SURVEILLANCE REQUIREMENTS (continued)

- The nominal trip setpoint and the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in a document incorporated by reference into the Updated Final Safety Analysis Report.

For BVPS, the document containing the nominal trip setpoint, the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band is the LRM.

For the RTS Functions with a CHANNEL CALIBRATION modified by Note (l), the Note requires that the instrument channel setpoint be reset to a value within the "as left" setpoint tolerance band on either side of the nominal trip setpoint or to a value that is more conservative than the nominal trip setpoint. The conservative direction is established by the direction of the inequality sign applied to the associated Allowable Value. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisfied in order to protect the safety analysis limits. If the channel can not be reset to a value within the required "as left" setpoint tolerance band on either side of the nominal trip setpoint, or to a value that is more conservative than the nominal trip setpoint (if required based on plant conditions) the channel is declared inoperable and the applicable ACTION is entered.

For the RTS Functions with a CHANNEL CALIBRATION modified by Notes (k) and (l), the "as found" and "as left" setpoint data obtained during COTs or CHANNEL CALIBRATIONS are programmatically trended to demonstrate that the rack drift assumptions used in the plant setpoint methodology are valid. If the trending evaluation determines that a channel is performing inconsistent with the uncertainty allowances applicable to the periodic surveillance test being performed, the channel is evaluated under the corrective action program. If the channel is not capable of performing its specified safety function, it is declared inoperable.

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

SR 3.3.1.10 is modified by Note 1 stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. In addition, this SR is modified by Note 2 stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists

BASES

SURVEILLANCE REQUIREMENTS (continued)

of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector calibration data and establishing detector operating conditions in accordance with approved plant procedures. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a COT of RTS interlocks. A successful test of any 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

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

SR 3.3.1.12

SR 3.3.1.12 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS. A successful test of any 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip. For the SI input from ESFAS, this test verifies the SI logic output to the reactor trip system.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

The SR is modified by a Note that excludes verification of setpoints from the TADOT. As the requirements for the ESFAS instrument channels, including actuation logic and Allowable Values are specified separately in LCO 3.3.2, the Functions affected by this SR have no setpoints associated with them.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.14

SR 3.3.1.14 verifies that the individual channel/train actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in the LRM. Individual component response times are not modeled in the analyses. This Surveillance is only required for instrument channels with response times that are assumed in the safety analyses. The LRM identifies instrument channels for which no response time is assumed in the safety analyses by indicating that the response time is not applicable.

The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor to the point at which the equipment reaches the required functional state (i.e., control and shutdown rods fully inserted in the reactor core).

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer Function set to one, or by such means as utilizing a step change input signal, with the resulting measured response time compared to the response time specified in the LRM. Alternately, the response time test can be performed with the time constants set to their nominal value, provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

BASES

SURVEILLANCE REQUIREMENTS (continued)

- NOTE -

The following alternate means for verifying response times (i.e., summation of allocated times) is only applicable to Unit 2.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," and WCAP-15413, "Westinghouse 7300A ASIC-Based Replacement Module Licensing Summary Report" provide the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter. WCAP-15413 provides bounding response times where 7300 cards have been replaced with ASICs cards.

As appropriate, each channel's response must be verified at the Frequency specified in the Surveillance Frequency Control Program. Each verification shall include at least one logic train such that both logic trains are verified at least once per the stated Frequency specified in the Surveillance Frequency Control Program. Response times cannot be determined during unit operation because equipment operation is required to measure response times. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.14 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

REFERENCES

1. Westinghouse Setpoint Methodology for Protection Systems, WCAP-11419, Rev. 6 (Unit 1) and WCAP-11366, Rev. 7 (Unit 2).

2. UFSAR, Chapter 7 (Unit 1 and Unit 2).

3. UFSAR Chapter 14 (Unit 1) and UFSAR Chapter 15 (Unit 2).

4. IEEE-279-1971.

5. 10 CFR 50.49.

6. Westinghouse Nuclear Safety Advisory Letter NSAL-00-016, Rod Withdrawal from Subcritical Protection in Lower Modes, December 4, 2000.

7. WCAP-14333-P-A, Rev. 1, “Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,” October 1998.

8. WOG-06-17, “WCAP-10271-P-A Justification for Bypass Test Time and Completion Time Technical Specification Changes for Reactor Trip on Turbine Trip,” June 20, 2006.

9. WCAP-15376-P-A, Rev. 1, “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” March 2003.

10. Amendment No. 282 (Unit 1) and Amendment No. 166 (Unit 2), December 29, 2008.

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the ESFAS as well as specifying LCOs on other 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 Analytical 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 when reaching the Analytical 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 Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action may actually occur.

The nominal trip setpoint is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For each automatic protective device there is a setting beyond which the device would not be able to perform its function due, for example, to greater than expected drift. The value of this setting is specified in the Technical Specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value.

The Allowable Value specified in Table 3.3.2-1 serves as the OPERABILITY limit such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value. 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 the assumptions stated in

BASES

BACKGROUND (continued)

the BVPS Unit 1 and Unit 2 setpoint methodology for protection systems (Ref. 3). 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.

In addition to the channel OPERABILITY guidance discussed above, the CHANNEL OPERATIONAL TEST (COT) and CHANNEL CALIBRATION Surveillance Requirements (SRs) specified on Table 3.3.2-1 for certain ESFAS Functions are modified by Notes (e) and (f) that specify additional Technical Specification requirements. The applicable Notes are specified directly on Table 3.3.2-1 next to the numerical SR designations for the affected ESFAS Functions. The additional Technical Specification requirements for these ESFAS Functions include OPERABILITY evaluations for setpoints found outside the as-found acceptance criteria band and the requirement to reset the setpoint to within the as-left tolerance of the nominal trip setpoint or a value that is more conservative than the nominal trip setpoint or declare the affected channel inoperable. These additional Technical Specification requirements are only applicable to the ESFAS Functions with the Notes modifying their COT and CHANNEL CALIBRATION SR numbers on Table 3.3.2-1.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured,

- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications, and

- Solid State Protection System (SSPS) including input, logic, and output bays: initiates the proper unit shutdown or engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and in some cases as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the nominal trip setpoint. The OPERABILITY of each transmitter or sensor is determined by either "as-found" calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor, as related to the channel behavior observed during performance of the CHANNEL CHECK.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. The safety analyses and associated ESFAS Functions are discussed in UFSAR Chapter 14 (Unit 1) and UFSAR Chapter 15 (Unit 2) (Ref. 1). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable or other trip device is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then

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require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1971 (Ref. 2). However, exceptions to the requirement for four channels are part of the design and licensing basis of the ESFAS (e.g., steam generator level instrumentation). The number of channels required for each unit parameter is specified in Technical Specification Table 3.3.2-1.

Allowable Values, ESFAS Setpoints, and LSSS

The nominal trip setpoints used in the bistables and other trip devices are based on the analytical limits stated in the BVPS Unit 1 and Unit 2 setpoint methodology for protection systems (Ref. 3). The selection of these nominal trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. The nominal trip setpoints account for calibration tolerances, instrument uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 4). The nominal trip setpoints are specified in the Licensing Requirements Manual (LRM). The Allowable Values specified in the Technical Specifications are determined by adding (or subtracting) the calibration accuracy of the trip device to the nominal trip setpoint in the non-conservative direction (i.e., toward or closer to the safety analysis limit) for the application. The Allowable Values remain conservative with respect to the analytical limits. For those channels that provide trip actuation via a bistable in the process racks, the calibration accuracy is defined by the rack calibration accuracy term. For a limited number of channels that provide trip actuation without being processed via the process racks (e.g., undervoltage relay channels) the Allowable Value is defined by device drift or repeatability (Ref. 3). The application of the calibration accuracy term (or device drift as applicable) to each ESFAS setpoint results in a "calibration tolerance band" for each setpoint. Thus, the trip setpoint value is considered a "nominal" value (i.e., expressed as a value with a calibration tolerance) for the purposes of the COT and CHANNEL CALIBRATION. The calibration tolerance band for each ESFAS setpoint is specified in plant procedures. A detailed description of the methodology used to calculate the Allowable Values and nominal trip setpoints including their explicit uncertainties, is provided in Reference 3 which incorporates all of the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the determination of each nominal trip setpoint and corresponding Allowable Value. The nominal trip setpoint entered into the trip device is more conservative than that specified by the Allowable Value to account for

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measurement errors detectable by the COT. The Allowable Value serves as the Technical Specification OPERABILITY limit. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the channel is considered OPERABLE. As discussed earlier, for certain ESFAS Functions, the COT and CHANNEL CALIBRATION SR numbers specified on Table 3.3.2-1 are modified by Notes that impose additional Technical Specification requirements for channel OPERABILITY.

The nominal trip setpoints are the values at which the trip devices are set and are the expected values to be achieved during calibration. The nominal trip setpoint value ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted to be within the calibration tolerance. Any trip device with a nominal trip setpoint is considered to be properly adjusted when the "as-left" setpoint value is within the calibration tolerance.

The nominal trip setpoint is based on the calculated total loop uncertainty per the plant specific methodology documented in the LRM. The setpoint methodology, used to derive the nominal trip setpoints, is based upon combining all of the uncertainties in the channels. Inherent in the determination of the nominal trip setpoints are the magnitudes of these channel uncertainties. Sensors and other instrumentation utilized in these channels should be capable of operating within the allowances of these uncertainty magnitudes. Occasional drift in excess of the allowance may be determined to be acceptable based on the other device performance characteristics. Device drift in excess of the allowance that is more than occasional, may be indicative of more serious problems and would warrant further investigation.

OPERABLE ESFAS Functions with setpoints maintained within the Allowable Values specified in the Technical Specifications ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Each channel can be tested on line except for manual initiation channels and the trip of all main feedwater pump channels, to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 3. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

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For most ESFAS Functions the Allowable Value specified on Table 3.3.2-1 is the LSSS required by 10 CFR 50.36. However, for certain ESFAS Functions, the COT and CHANNEL CALIBRATION SR numbers specified on Table 3.3.2-1 are modified by Notes (e) and (f) that impose additional Technical Specification Requirements for channel OPERABILITY and change the LSSS for the affected Functions. For each ESFAS Function in Table 3.3.2-1 with Notes modifying the required COT and CHANNEL CALIBRATION SR numbers, the nominal trip setpoint specified in the LRM is the LSSS.

This definition of the LSSS is consistent with the guidance issued to the industry through correspondence with Nuclear Energy Institute (NEI) (Reference NRC-NEI Letter dated September 7, 2005). The definition of LSSS values continues to be discussed between the industry and the NRC, and further modifications to these Technical Specification Bases will be implemented as guidance is provided.

Table 3.3.2-1 Notes (e) and (f) are applicable to the COT and CHANNEL CALIBRATION SRs for specific instrument functions since changes to Allowable Values associated with these instrument functions were already under review by the NRC at the time the revised NRC setpoint criteria were documented and made available to the industry in an NRC letter to the NEI. Changes to the remaining instrument functions may be pursued after guidance endorsed by both the NRC and NEI is issued.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of inputs from field contacts, control board switches, and the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The SSPS performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The input signals from field contacts, control board switches, and bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations

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indicative of various transients. If a required logic matrix combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Each SSPS train has a built in testing device that can automatically test the selected decision logic matrix functions and partially test the actuation relays while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

The actuation of ESF components is accomplished through master and slave relays. The SSPS energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays that provide actuation signals to ESF components are routinely tested to ensure operation. The test of the master relays energizes the relay, which then operates the contacts and applies a low voltage to the associated slave relays. The low voltage is not sufficient to actuate the slave relays but only demonstrates signal path continuity. The SLAVE RELAY TEST actuates the devices if their operation will not interfere with continued unit operation. For the latter case, actual component operation is prevented and slave relay contact operation is verified by a continuity check of the circuit containing the slave relay.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. Functions not explicitly credited in the safety analysis, may be implicitly credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions not explicitly analyzed and may be anticipatory in nature or serve as backups to Functions that are explicitly credited in the accident analysis to provide defense in depth (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. A channel is OPERABLE provided the trip setpoint "as-found" value does not exceed its associated Allowable Value and provided the trip setpoint "as-left" value is adjusted to a value within the calibration tolerance band of the nominal trip setpoint. A trip setpoint may be set more conservative than the nominal trip setpoint as necessary in response to plant conditions provided that the ± calibration tolerance band remains the same and the Allowable Value is administratively controlled accordingly in the conservative direction to meet the assumptions of the setpoint methodology. The conservative direction is established by the direction of the inequality applied to the Allowable Value. Failure of any instrument may render the affected channel(s) inoperable and reduces the reliability of the affected Functions.

In addition to the channel OPERABILITY guidance discussed above, the COT and CHANNEL CALIBRATION SRs specified on Table 3.3.2-1 for certain ESFAS Functions are modified by Notes (e) and (f) that specify additional Technical Specification requirements. The applicable Notes are specified directly on Table 3.3.2-1 next to the numerical SR designations for the affected RTS Functions. The additional Technical Specification requirements for these ESFAS Functions include OPERABILITY evaluations for setpoints found outside the as-found acceptance criteria band and the requirement to reset the setpoint to within the as-left tolerance of the nominal trip setpoint or a value that is more conservative than the nominal trip setpoint or declare the affected channel inoperable. These additional Technical Specification requirements are only applicable to the ESFAS Functions with the Notes modifying their COT and CHANNEL CALIBRATION SR numbers on Table 3.3.2-1.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1. Safety Injection

Safety Injection (SI) provides two primary functions:

1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to ≤ 2200°F), and

2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation,
- Reactor Trip,
- Turbine Trip,
- Feedwater Isolation,
- Start of auxiliary feedwater (AFW) pumps, and
- Enabling automatic switchover of Emergency Core Cooling Systems (ECCS) suction to containment sump.

These other functions ensure:

- Isolation of nonessential systems through containment penetrations,
- Trip of the turbine and reactor to limit power generation,
- Isolation of main feedwater (MFW) to limit secondary side mass losses,
- Start of AFW to ensure secondary side cooling capability, and
- Enabling ECCS suction switchover from the refueling water storage tank (RWST) to the containment sump on RWST Level Extreme Low to ensure continued cooling via use of the containment sump.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Safety Injection - Manual Initiation

The LCO requires one channel per train to be OPERABLE. The operator can initiate SI at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals except for the Unit 1 automatic high head safety injection (HHSI) flow path isolation valves when LCO 3.4.12, "Overpressure Protection System," is applicable. Consistent with the requirements of LCO 3.4.12, in MODE 4 when any RCS cold leg temperature is ≤ the enable temperature specified in the PTLR, the Unit 1 automatic HHSI flow path must be isolated with power removed from the isolation valves. Therefore, when operating in the MODE 4 Applicability of LCO 3.4.12, the manual initiation of Unit 1 SI will require additional manual valve operation to establish an SI injection flow path.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one switch and the interconnecting wiring to the actuation logic cabinet. Each switch actuates both trains. This configuration does not allow testing at power.

b. Safety Injection - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

In the event an inadvertent SI is initiated, the block of the automatic actuation logic introduced by a reset of safety injection must be removed by resetting (closure) of the reactor trip breakers after the inadvertent initiation providing that all trip input signals have reset due to stable plant conditions. When the Automatic Actuation Logic is required OPERABLE and is blocked after an inadvertent SI, the affected train(s) of Automatic Actuation Logic are considered inoperable and the Technical Specification ACTIONS are applicable until the Automatic Actuation Logic is restored to OPERABLE status.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4; however, only the actuation relays are required to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection - Containment Pressure - High

This signal provides protection against the following accidents:

- SLB inside containment, and
- Feed line break inside containment.

Containment Pressure - High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic.

The high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure - High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Safety Injection - Pressurizer Pressure - Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve,
- SLB,
- A spectrum of rod cluster control assembly ejection accidents (rod ejection),
- Inadvertent opening of a pressurizer relief or safety valve,
- LOCAs, and
- SG Tube Rupture.

The Pressurizer Pressure - Low protection Function provides no input to any control functions. Pressurizer pressure control is accomplished by two separate channels independent of the pressurizer pressure protection channels used for ESFAS. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic.

The transmitters could experience adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-11) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the P-11 setpoint. Automatic SI actuation below this pressure setpoint is then performed by the Containment Pressure - High signal.

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Safety Injection - Steam Line Pressure - Low

Steam Line Pressure - Low provides protection against the following accidents:

- SLB,
- Feed line break, and
- Inadvertent opening of an SG relief or an SG safety valve.

Steam Line Pressure - Low also provides input to steam generator level control; however, only three OPERABLE channels per steam line are provided. If a steam pressure sensor fails high or low, the steam generator level control system would eventually recover based upon the level input alone, assuming that a high level or low level trip setpoint is not reached. If the steam generator level setpoint is reached and protective action is required, a reactor trip (on low steam generator level) or turbine trip (on high steam generator level) occurs automatically. In this case, steam generator level is used to mitigate the event and not steam pressure. A single failure in a steam generator level channel could be assumed; however, the reactor trip would still occur on steam generator level. A second failure in another steam pressure transmitter would not preclude a trip from occurring on steam generator level. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on any steam line.

The Unit 1 transmitters will not experience adverse environmental conditions during a secondary side break. The Unit 2 transmitters are located where they may experience adverse environmental conditions during a secondary side break outside containment. However, for Unit 2, the safety analysis limit for the steam line break inside containment is more limiting than the safety analysis limit for the steam line break outside containment. As such, the Unit 2 Trip Setpoint is based on the more limiting result of the safety analysis for a steam line break inside containment which does not require an adverse environmental uncertainty. The magnitude of the difference between the inside and outside safety analysis limits is greater than or equal to the potential error that could result from an adverse environment. Therefore, the trip setpoints for both units only reflect steady state instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function is anticipatory in nature and has a lead/lag ratio of 50/5.

Steam Line Pressure - Low must be OPERABLE in MODES 1, 2, and 3 (above P-11) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, feed line break is not a concern. Inside containment SLB will be terminated by automatic steam line isolation via Containment Pressure-Intermediate High High, and outside containment SLB will be terminated by the Steam Line Pressure - Negative Rate - High signal for steam line isolation. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

2. Containment Spray Systems

Containment Spray provides five primary functions:

1. Lowers containment pressure and temperature after an HELB in containment,

2. Reduces the amount of radioactive iodine in the containment atmosphere,

3. Adjusts the pH of the water in the containment recirculation sump after a large break LOCA,

4. Mixes the containment atmosphere and minimizes the amount of hydrogen accumulation, and

5. Removes containment heat.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure,

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure,

- Minimize corrosion of the components and systems inside containment following a LOCA,

- Control subcompartment and general area hydrogen concentrations to less than 4% by volume, and

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- Remove decay heat to ensure that the containment gas and sump water temperatures are within the containment liner and piping thermal stress limits.

The containment spray actuation signal starts the Quench Spray pumps and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is drawn from the RWST by the Quench Spray pumps. The Quench Spray pumps are manually stopped following receipt of a low RWST level alarm. The Recirculation Spray pumps are started automatically and take suction from the containment sump to continue containment spray. Sodium tetraborate is added to the recirculation spray solution as the sodium tetraborate storage baskets are submerged by water accumulating in the containment sump. Recirculation spray is actuated manually or by Containment Pressure - High High coincident with RWST Level Low.

a.(1) Quench Spray - Manual Initiation

The operator can initiate quench spray at any time from the control room by simultaneously actuating two containment spray actuation switches in the same train. Because an inadvertent actuation of quench spray could have undesirable consequences, two switches must be actuated simultaneously to initiate quench spray. There are two sets of two switches each in the control room. Simultaneously actuating the two switches in either set will actuate quench spray in both trains in Unit 2 and one train in Unit 1. Two Manual Initiation switches in each train are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function. Manual Initiation of quench spray also actuates Phase B containment isolation. Note that manual initiation of containment spray will initiate a recirculation spray pump start if an RWST Level Low signal is present. Alternatively, an operator can individually start each recirculation spray pump using the control board pump switches.

a.(2) Quench Spray - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment. Manual and automatic initiation of quench spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a quench spray, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4; however, only the actuation relays are required to support manual initiation of quench spray. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

a.(3) Quench Spray - Containment Pressure - High High

This signal provides protection against a LOCA or an SLB inside containment. The transmitters will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This is one of two Functions that require the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate the containment spray systems. Note that this Function also has the inoperable channel placed in bypass rather than trip to decrease the probability of an inadvertent actuation.

This Function uses four channels in a two-out-of-four logic configuration. Additional redundancy is warranted because this Function is energized to trip. Containment Pressure - High High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure - High High setpoints.

b.(1) Recirculation Spray - Automatic Actuation Logic

This LCO requires two trains to be OPERABLE. The trains consist of the actuation logic and associated master relays for this Function. The actuation logic consists of all circuitry housed within the actuation subsystems. The LCO for this Function

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

does not include requirements for slave relay OPERABILITY. The SRs for this Function do not include a SLAVE RELAY TEST due to equipment safety concerns (inadvertent pump start) if such a test was performed at power. The verification of required slave relay OPERABILITY for this Function is included in LCO 3.6.7 Recirculation Spray System (SR 3.6.7.3.b). The Recirculation Spray System SR is a periodic Surveillance that allows the required SLAVE RELAY TEST to be performed safely. Therefore, LCO 3.6.7 addresses the OPERABILITY of the slave relays for this Function.

b.(2) Recirculation Spray - RWST Level Low coincident with Containment Pressure-High High

This LCO requires three RWST Level Low channels and four Containment Pressure High High channels to be OPERABLE. A Level Low in the RWST coincident with a Containment Pressure-High High signal automatically initiates recirculation spray. Recirculation spray is the primary method of heat removal from the containment environment following a LOCA. The RWST Level Low Allowable Value has both upper and lower limits. The lower limit is selected to ensure that containment temperatures remain within safety analysis limits and that adequate NPSH is available to the LHSI pumps. The upper limit ensures adequate NPSH to the recirculation spray pumps.

The RWST Level Low Function uses three RWST level transmitters in a two out of three coincident logic. These transmitters provide no control functions. The transmitters will not experience any adverse environmental conditions and, therefore, the trip setpoint reflects only steady state instrument uncertainties. The RWST level logic is configured in a de-energize to trip configuration.

The Containment Pressure-High High signal is described in Quench Spray, Containment Pressure-High High (item 2.a(3)).

The RWST Level Low and Containment Pressure High High Functions must be OPERABLE in MODES 1, 2 and 3 when there is a potential for a LOCA to occur, to ensure a continued supply of water for the recirculation spray pumps. These Functions are not required to be OPERABLE in MODES 4, 5 and 6 because there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure - High High setpoints.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Containment Isolation

Containment Isolation provides isolation of the containment atmosphere, and all process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines, except component cooling water (CCW) and cooling water to the containment air recirculation fan cooling coils, and the Unit 1 containment instrument air, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW is required to support RCP operation, not isolating CCW on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CCW on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually via the automatic actuation relays. CCW is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and motors. The cooling water to the containment air recirculation fan cooling coils is not isolated by a Phase A signal to allow continued containment cooling. The Unit 1 containment instrument air is not isolated by a Phase A signal to allow instrument air to be available to support valve operation inside containment (e.g., CCW valves). All process lines required to be isolated under accident conditions and not equipped with automatic isolation valves are manually closed, or otherwise isolated, prior to reaching MODE 4 (except when open under administrative controls).

Manual Phase A Containment Isolation is accomplished by either of two switches in the control room. Either switch actuates both trains.

The Phase B signal isolates CCW and cooling water to the containment air recirculation fan cooling coils and containment instrument air (for Unit 1 only). This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating these additional systems at the higher pressure does not pose a challenge to the containment boundary because the systems are closed loops inside containment. The systems are continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of system design and Phase B isolation ensures the systems are not a potential path for radioactive release from containment.

Phase B containment isolation is actuated by Containment Pressure - High High, or manually, via the automatic actuation relays, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure - High High, a LOCA or SLB must have occurred and containment spray must have been actuated. RCP operation will no longer be required and CCW to the RCPs is, therefore, no longer necessary.

Manual Phase B Containment Isolation is accomplished by the same switches that actuate Containment Spray. When the two switches in either set are actuated simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains in Unit 2 and one train in Unit 1.

a. Containment Isolation - Phase A Isolation

(1) Phase A Isolation - Manual Initiation

Manual Phase A Containment Isolation is actuated by either of two switches in the control room. Either switch actuates both trains.

(2) Phase A Isolation - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4; however, only the actuation relays are required to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation - Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

b. Containment Isolation - Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2.a(3). The Containment Pressure actuation of Phase B Containment Isolation is energized to actuate in order to minimize the potential of spurious actuations that may damage the RCPs.

(1) Phase B Isolation - Manual Initiation

The manual Phase B Containment Isolation is accomplished by the manual Containment Spray switches described in Function 2.a(1).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(2) Phase B Isolation - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of Phase B containment isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a Phase B containment isolation, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4; however, only the actuation relays are required to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase B containment isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase B Isolation - Containment Pressure - High High

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.a(3) above.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, at most. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the steam lines depressurize. For Unit 2 which does not have steam line check valves, Steam Line Isolation also mitigates the effects of a feed line break and ensures a source of steam for the turbine driven AFW pump during a feed line break.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Steam Line Isolation - Manual Initiation (Unit 2 only)

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are two switches per train in the control room and simultaneous actuation of both switches in a train can initiate a system level action to immediately close all MSIVs. The LCO requires two channels per train to be OPERABLE. The Unit 1 design does not include a system level manual steam line isolation capability. Unit 1 manual isolation of the MSIVs can be accomplished via the individual manual control switches for each MSIV. The capability to manually actuate each MSIV is an OPERABILITY requirement of Technical Specification 3.7.2, "MSIVs."

b. Steam Line Isolation - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed and de-activated. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

c. Steam Line Isolation - Containment Pressure - Intermediate High High

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to maintain at least two unfaulted SGs as a heat sink for the reactor, and to limit the mass and energy release to containment. Containment Pressure - Intermediate High High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. The transmitters and electronics will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Containment Pressure - Intermediate High High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function must be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure - Intermediate High High setpoint.

d. Steam Line Isolation - Steam Line Pressure

(1) Steam Line Pressure - Low

Steam Line Pressure - Low provides closure of the MSIVs in the event of an SLB to maintain two unfaulted SGs as a heat sink for the reactor, and to limit the mass and energy release to containment. This Function provides closure of the MSIVs in the event of a feed line break to ensure a supply of steam for the turbine driven AFW pump. Steam Line Pressure - Low was discussed previously under SI Function 1.e.

The Steam Line Pressure - Low Function must be OPERABLE in MODES 1, 2, and 3 (above P-11), with any main steam valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, an inside containment SLB will be terminated by automatic actuation via Containment Pressure - Intermediate High High. Stuck valve transients and outside containment SLBs will be terminated by the Steam Line Pressure - Negative Rate - High signal for Steam Line Isolation below P-11 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(2) Steam Line Pressure - Negative Rate - High

Steam Line Pressure - Negative Rate - High provides closure of the MSIVs for an SLB when less than the P-11 setpoint, to maintain two unfaulted SGs as a heat sink for the reactor, and to limit the mass and energy release to containment. When the operator manually blocks the Steam Line Pressure - Low main steam isolation signal when less than the P-11 setpoint, the Steam Line Pressure - Negative Rate - High signal is automatically enabled. Steam Line Pressure - Negative Rate - High provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy requirements with a two-out-of-three logic on any steam line.

Steam Line Pressure - Negative Rate - High must be OPERABLE in MODE 3 when less than the P-11 setpoint, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In MODES 1 and 2, and in MODE 3, when above the P-11 setpoint, this signal is automatically disabled and the Steam Line Pressure - Low signal is automatically enabled. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to have an SLB or other accident that would result in a release of significant quantities of energy to cause a cooldown of the RCS.

While the transmitters may experience elevated ambient temperatures due to an SLB, the Function is based on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

5. Turbine Trip and Feedwater Isolation

The primary functions of the Turbine Trip and Feedwater Isolation signals are to prevent damage to the turbine due to water in the steam lines, and to stop the excessive flow of feedwater into the SGs. These Functions are necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Function is actuated by an SI signal or when the level in any SG exceeds the high high setpoint, and performs the following functions:

- Trips the main turbine,
- Trips the MFW pumps, and
- Initiates feedwater isolation.

a. Turbine Trip and Feedwater Isolation - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

b. Turbine Trip and Feedwater Isolation - Steam Generator Water Level - High High (P-14)

The Allowable Value for this Function is specified in percent of narrow range instrument span. This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments provide input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Three OPERABLE channels on each SG satisfy the requirements with a two-out-of-three logic on any SG. Three channels are acceptable in this application because functional separation between the protection and control systems is accomplished by the use of a median signal selector switch.

The transmitters do not experience a severe environment and therefore, the trip setpoint reflects only steady state instrument uncertainties.

c. Turbine Trip and Feedwater Isolation - Safety Injection

Turbine Trip and Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Turbine Trip and Feedwater Isolation Functions must be OPERABLE in MODES 1, 2, and 3 except when all Main Feedwater Lines are isolated by either closed and deactivated MFIVs, or MFRVs and associated bypass valves, or closed manual valves. In these MODES the MFW System and turbine generator may be in service. In MODES 4, 5, and 6, the MFW System and the turbine generator are not in service and this Function is not required to be OPERABLE.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the Primary Plant Demineralized Water Storage Tank. The River Water (Unit 1) and Service Water (Unit 2) systems provide a backup source of water for the AFW System. The AFW System is aligned so that upon a pump start, flow is initiated to the SGs immediately.

a. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

b. Auxiliary Feedwater - Steam Generator Water Level - Low Low

The Allowable Value for this Function is specified in percent of narrow range instrument span. SG Water Level - Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. The actuation of two-out-of-three channels of SG Low-Low Level on any one SG will start the turbine-driven AFW pump. The actuation of two-out-of-three channels of SG Low-Low Level on any two SGs will start the motor-driven AFW pumps. SG Water Level - Low Low provides input to the SG Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system which may then require a protection function actuation and a single failure in the other channels providing the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

protection function actuation. Three OPERABLE channels per SG are required to satisfy the requirements with two-out-of-three logic. Three channels are acceptable in this application because functional separation between the protection and control systems is accomplished by the use of a median signal selector switch.

With the transmitters possibly experiencing adverse environmental conditions (feed line break), the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

c. Auxiliary Feedwater - Safety Injection

An SI signal starts the motor driven and turbine driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

Functions 6.a through 6.c must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. AFW pump start is described on previous page. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

d. Auxiliary Feedwater - Undervoltage Reactor Coolant Pump

A loss of power on the buses that provide power to the RCPs provides indication of a pending loss of RCP forced flow in the RCS. A loss of power on two or more RCPs, will start the turbine driven AFW pump to ensure that two SGs contain enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

e. Auxiliary Feedwater - Trip of All Main Feedwater Pumps

A Trip of all MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. The MFW pumps are equipped with

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a breaker position sensing device. An open supply breaker indicates that the pump is not running. A trip of all running MFW pumps (two-out-of-two MFW pump breakers open with either pump control switch in the after-start position) starts the motor driven AFW pumps to ensure that two SGs are available with water to act as the heat sink for the reactor.

For Unit 1 only, the “A” and “B” MFW pumps each have tandem electric motors. The circuits that accomplish starting of both motor driven AFW pumps upon the tripping of both MFW pumps include a cell switch contact on each of the four tandem motor pump breakers. Actuation of the MFW pump motor breakers cell switches results in the closure of two series contacts in the start circuit for each motor driven AFW pump. The motor driven AFW pump start signals are then generated provided that either MFW pump control switch is in the after-start position. Although there are two actuation channels per MFW pump, Table 3.3.2-1 Function 6.e requires one channel per MFW pump to be OPERABLE. The combination of these cell switches and associated circuitry that comprise the required channels of “one per pump” must be capable of initiating a start signal to at least one of the two motor driven AFW pumps upon the tripping of both MFW pumps. Therefore, a Table 3.3.2-1 Function 6.e required channel consists of a motor breaker cell switch on one of the tandem motors breakers and the required circuitry (including MFW pump control switches contacts) up to and including the series contact in the motor driven AFW pump actuation circuit. If one or both MFW pump trip channels associated with the start of the same train of motor driven AFW pump are inoperable, the required channels of “one per pump” continues to be met provided that the remaining trip channels are OPERABLE and capable of generating a start signal for the other motor driven AFW pump train.

For Unit 2 only, the “A” and “B” MFW pumps each have tandem electric motors. The circuits that accomplish starting of both motor driven AFW pumps upon the tripping of both MFW pumps consist of a pump motor breaker cell switch contact on the designated “A” MFW pump motor and a breaker cell switch contact on the designated “B” MFW pump motor. The other “A” and “B” MFW pump motor cell switches are not utilized to directly start the motor driven AFW pumps. Actuation of the “A” and “B” MFW pump motor breakers cell switches results in the closure of two series contacts and the generation of a start signal for the “A” and “B” motor driven AFW pumps provided that either MFW pump control switch is in the after-start position.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

There is a “one per pump” actuation channel associated with the designated “A” MFW pump motor breaker cell switch and a “one per pump” actuation channel associated with the designated “B” MFW pump motor breaker cell switch. Therefore, in order to meet the “one per pump” requirement specified in Table 3.3.2-1, a channel consisting of a motor breaker cell switch for “A” MFW pump motor and a motor breaker cell switch for the “B” MFW pump motor and the required circuitry (including MFW pump control switches contacts) up to and including the series contacts in the motor driven AFW pumps actuation circuits must be OPERABLE.

Functions 6.d and 6.e must be OPERABLE in MODES 1 and 2. This ensures that two SGs are provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODES 3, 4, and 5, the RCPs and MFW pumps may be normally shut down, and thus neither pump trip is indicative of a condition requiring automatic AFW initiation.

7. Automatic Switchover to Containment Sump

At the end of the injection phase of a LOCA, the RWST will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the ECCS pumps is automatically switched to the containment recirculation sump. In Unit 1, the low head SI (LHSI) pumps and containment recirculation spray (RS) pumps draw water from the containment sump. The RS pumps pump the water through the RS heat exchanger to the recirculation spray headers. The LHSI pumps circulate the water back to the reactor and provide suction to the High Head SI (HHSI) pumps. In Unit 2, during the recirculation phase, one RS pump per train provides the low head injection function and suction to the HHSI pump and one RS pump per train provides the recirculation spray function. Both the Unit 2 RS pumps on each train draw water from the containment sump and pump water through an RS heat exchanger. Switchover from the RWST to the containment sump must occur before the RWST empties to prevent damage to the pumps and a loss of core cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support ESF pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. This ensures the reactor remains shut down in the recirculation mode.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Automatic Switchover to Containment Sump - Automatic Actuation Logic

This LCO requires two trains to be OPERABLE. The trains consist of the actuation logic and associated master relays for this Function. The actuation logic consists of all circuitry housed within the actuation subsystems. The LCO for this Function does not include requirements for slave relay OPERABILITY. The SRs for this Function do not include a SLAVE RELAY TEST due to equipment safety concerns if such a test was performed at power. The verification of required slave relay OPERABILITY for this Function is included in LCO 3.5.2, ECCS - Operating (SRs 3.5.2.5 and 3.5.2.6). These ECCS SRs are Surveillances that allow the required SLAVE RELAY TEST to be performed safely. Therefore, LCO 3.5.2 addresses the OPERABILITY of the slave relays for this Function.

b. Automatic Switchover to Containment Sump - Refueling Water Storage Tank (RWST) Level Extreme Low Coincident With Safety Injection

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. A Level Extreme Low in the RWST coincident with an SI signal provides protection against a loss of water for the ECCS pumps and indicates the end of the injection phase of the LOCA. The SI interlock is maintained by latching relays until reset manually. The RWST is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability due to the energize to trip design of these channels.

The RWST Level Extreme Low Allowable Value has both upper and lower limits. The lower limit is selected to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage. The upper limit is selected to ensure enough borated water is injected to ensure the reactor remains shut down. The upper limit also ensures adequate water inventory in the containment sump to provide ECCS pump suction.

The transmitters will not experience any adverse environmental conditions and, therefore, the trip setpoint reflects only steady state instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Automatic switchover occurs only if the RWST Level Extreme Low signal is coincident with SI. This prevents accidental switchover during normal operation. Accidental switchover could damage ECCS pumps if they are attempting to take suction from an empty sump. The automatic switchover Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

These Functions must be OPERABLE in MODES 1, 2, 3, and 4 when there is a potential for a LOCA to occur, to ensure a continued supply of water for the ECCS pumps. These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. System pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

8. Engineered Safety Feature Actuation System Interlocks

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses.

a. Engineered Safety Feature Actuation System Interlocks - Reactor Trip, P-4

The P-4 interlock is enabled when a reactor trip breaker (RTB) and its associated bypass breaker is open. Although SI actuation may be manually reset after a 75 second delay, if P-4 is enabled, subsequent automatic SI initiation is blocked until P-4 is reset (RTBs closed). This Function allows operators to take manual control of SI systems after the initial phase of injection is complete without further automatic SI actuations taking place. The functions of the P-4 interlock are:

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- Trip the main turbine,
- Isolate MFW Regulating Valves with coincident low T_{avg},
- Prevent automatic reactuation of SI after a manual reset of SI, and
- Prevent opening of the MFW isolation valves if they were closed on SI or SG Water Level - High High with low T_{avg}.

Each of the above Functions is interlocked with P-4 to avert or reduce the continued cooldown of the RCS following a reactor trip. An excessive cooldown of the RCS following a reactor trip could cause an insertion of positive reactivity with a subsequent increase in generated power or could result in an SI actuation. To avoid such a situation, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system.

None of the noted Functions serves a mitigation function in the unit licensing basis safety analyses. Only the turbine trip and isolation of the MFW Regulating Valves coincident with low T_{avg} Functions are explicitly assumed since they are an immediate consequence of the reactor trip Function. However, none of the P-4 Functions listed above associated with the reactor trip signal, is required to show that the unit licensing basis safety analysis acceptance criteria are not exceeded.

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable trip setpoint with which to associate a trip setpoint and Allowable Value.

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an excessive cooldown transient.

b. <u>Engineered Safety Feature Actuation System Interlocks - Pressurizer Pressure, P-11</u>

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of SI or main steam line isolation. With two-out-of-three pressurizer pressure channels

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(discussed previously) less than the P-11 setpoint, the operator can manually block the Pressurizer Pressure - Low and Steam Line Pressure - Low SI signals and the Steam Line Pressure - Low steam line isolation signal (previously discussed). When the Steam Line Pressure - Low steam line isolation signal is manually blocked, a main steam isolation signal on Steam Line Pressure - Negative Rate - High is enabled. This provides protection for an SLB by closure of the MSIVs. With two-out-of-three pressurizer pressure channels above the P-11 setpoint, the Pressurizer Pressure - Low and Steam Line Pressure - Low SI signals and the Steam Line Pressure - Low steam line isolation signal are automatically enabled. The operator can also enable these trips by use of the respective manual reset switches. When the Steam Line Pressure - Low steam line isolation signal is enabled, the main steam isolation on Steam Line Pressure - Negative Rate - High is disabled. The Trip Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

c. Engineered Safety Feature Actuation System Interlocks - T_{avg} - Low Low, P-12

On increasing reactor coolant temperature, the P-12 interlock provides an arming signal to the Steam Dump System. On a decreasing temperature, the P-12 interlock removes the arming signal to the Steam Dump System to prevent an excessive cooldown of the RCS due to a malfunctioning Steam Dump System. Although the P-12 interlock Function provides protection that helps prevent an excessive cooldown event, it is not credited in any safety analysis as the primary actuation instrumentation necessary to mitigate a design basis accident.

Since T_{avg} is used as an indication of bulk RCS temperature, this Function meets redundancy requirements with one OPERABLE channel in each loop. These channels are used in two-out-of-three logic. Although T_{avg} is used for control system input, three channels are acceptable in this application because functional separation between the protection and control systems is accomplished by the use of a median signal selector.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when a malfunction of the Steam Dump System could result in an excessive cooldown of the RCS. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an excessive RCS cooldown event.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

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

Condition B applies to manual initiation of:

- SI,
- Containment Spray,

BASES

ACTIONS (continued)

- Phase A Isolation, and
- Phase B Isolation.

In addition, Condition B applies to the Automatic Actuation Logic for the Automatic Switchover to the Containment Sump Function. This action addresses the train orientation of the SSPS for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each manual Function, and the low probability of an event occurring during this interval. In the case of the Automatic Actuation Logic for the Containment sump switchover, the Completion Time is reasonable considering that the other automatic actuation logic train is OPERABLE and that manual actions may be taken to align the required equipment to the containment sump. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

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

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI,
- Containment Spray,
- Phase A Isolation, and
- Phase B Isolation.

This Action Condition is intended to address an inoperability of the actuation logic or relays associated with an ESFAS train that affects the integrated ESFAS response to an actuation signal. The Completion Time of this ACTION (24 hours) is based on the assumption that multiple ESF

BASES

ACTIONS (continued)

components within a train are affected by the failure of the actuation logic or relays. Therefore, the Completion Time of this Action is appropriate and applicable whenever more than one ESF System is affected by the inoperable train of logic or relays.

However, if one or more inoperable actuation relays in an ESFAS train only affect a single ESF component or system, the applicable Actions Condition for the affected ESF component or system should be entered and the Completion Time of this Action Condition is not appropriate or applicable.

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 6. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 5 within an additional 30 hours (60 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Reference 5) that 4 hours is the average time required to perform train surveillance.

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements for WCAP-14333-P-A, Rev. 1 (Reference 6), Tier 2 insights must be included in the decision making process before removing a logic train from service and implementing the extended (risk-informed) Completion Time for a logic train approved in Reference 7. These "Tier 2 restrictions" are considered to be necessary to avoid risk significant plant configurations during the time a logic train is inoperable.

BASES

ACTIONS (continued)

Entry into Condition C for an inoperable logic train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition C may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition C entry. In addition, it is possible that equipment failure may occur after the logic train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures in place to address the requirements of 10 CFR 50.65(a)(4) require assessment of the emergent condition with appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable logic train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition C when a logic train is inoperable:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained. Note that Technical Specification 3.5.2, ECCS Operating, ensures that this restriction is met. Therefore, this restriction does not have to be implemented by a separate procedure or program.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.

- Activities on electrical systems (AC and DC power) and cooling systems (service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

BASES

ACTIONS (continued)

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

Condition D applies to:

- Containment Pressure - High,
- Pressurizer Pressure - Low,
- Steam Line Pressure - Low,
- Containment Pressure - Intermediate - High High,
- Steam Line Pressure - Negative Rate - High,
- SG Water level - Low Low,
- SG Water level - High High (P-14), and
- RWST Level Low.

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements. For the Functions listed above, other than RWST Level Low, the 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 6. For RWST Level Low, the 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 7.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. The 12 hours allowed for testing, are justified in References 6 and 7.

BASES

ACTIONS (continued)

E.1, E.2.1, and E.2.2

Condition E applies to:

- Containment Spray Containment Pressure - High High, and
- Containment Phase B Isolation Containment Pressure - High High.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 72 hours allowed to restore the channel to OPERABLE status or to place it in the bypassed condition is justified in Reference 6. The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 72 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows one channel to be bypassed for up to 12 hours for surveillance testing. Placing a second channel in the bypass condition for up to 12 hours for testing purposes is acceptable based on the results of Reference 6.

BASES

ACTIONS (continued)

F.1, F.2.1, and F.2.2

Condition F applies to:

- The Unit 2 Manual Initiation of Steam Line Isolation, and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

G.1, G.2.1, and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation, Turbine Trip and Feedwater Isolation, and AFW actuation Functions.

This Action Condition is intended to address an inoperability of the actuation logic or relays associated with an ESFAS train that affects the integrated ESFAS response to an actuation signal. The Completion Time of this ACTION (24 hours) is based on the assumption that multiple ESF components within a train are affected by the failure of the actuation logic or relays. Therefore, the Completion Time of this Action is appropriate and applicable whenever more than one ESF System is affected by the inoperable train of logic or relays.

However, if one or more inoperable actuation relays in an ESFAS train only affect a single ESF component or system, the applicable Actions Condition for the affected ESF component or system should be entered and the Completion Time of this Action Condition is not appropriate or applicable.

BASES

ACTIONS (continued)

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 6. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Reference 5) assumption that 4 hours is the average time required to perform train surveillance.

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements for WCAP-14333-P-A, Rev. 1 (Reference 6), Tier 2 insights must be included in the decision making process before removing a logic train from service and implementing the extended (risk-informed) Completion Time for a logic train approved in Reference 7. These "Tier 2 restrictions" are considered to be necessary to avoid risk significant plant configurations during the time a logic train is inoperable.

Entry into Condition G for an inoperable logic train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition G may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition G entry. In addition, it is possible that equipment failure may occur after the logic train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of unplanned equipment failure, the programs and procedures in place to address the requirements of 10 CFR 50.65(a)(4) require assessment of the emergent condition with

BASES

ACTIONS (continued)

appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable logic train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition G when a logic train is inoperable:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained. Note that Technical Specification 3.5.2, ECCS Operating, ensures that this restriction is met. Therefore, this restriction does not have to be implemented by a separate procedure or program.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.

- Activities on electrical systems (AC and DC power) and cooling systems (service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

H.1 and H.2

Condition H applies to:

- Undervoltage Reactor Coolant Pump.

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two logic will result in actuation. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit to be placed in MODE 3 within

BASES

ACTIONS (continued)

the following 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 6.

I.1 and I.2

Condition I applies to the motor driven AFW pump start on trip of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the motor driven AFW System pumps.

For Unit 1 only, the Required Action for Condition I to restore the channel to OPERABLE status is applicable when (three out of the four MFW pumps trip channels are inoperable) or (two out of four channels not associated with the same motor driven AFW pump are inoperable). In these two cases, a start of either motor driven AFW pump can no longer be initiated due to a trip of all MFW pumps. A detailed description of the actuation circuit(s) is provided in the Bases for Function 6.e of this Specification.

For Unit 2 only, the Required Action for Condition I to restore the channel to OPERABLE status is applicable when one MFW pump's trip channel is inoperable. In this case, a start of either motor driven AFW pump can no longer be initiated due to a trip of all MFW pumps. A detailed description of the actuation circuit is provided in the Bases for Function 6.e of this Specification.

If a channel is inoperable, 48 hours are allowed to return it to an OPERABLE status. If the function cannot be returned to an OPERABLE status, 6 hours are allowed to place the unit in MODE 3. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above. The allowance of 48 hours to return the train to an OPERABLE status is justified in Reference 5.

BASES

ACTIONS (continued)

J.1, J.2.1, and J.2.2

Condition J applies to:

- RWST Level Extreme Low Coincident with Safety Injection.

RWST Level Extreme Low Coincident with SI provides actuation of switchover to the containment sump. Note that this Function requires the bistables to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 72 hours is sufficient to ensure that the Function remains OPERABLE, and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed low). If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 72 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

The Required Actions are modified by a Note that allows placing a channel in the bypass condition for up to 12 hours for surveillance testing. The 72 hours to place a channel in bypass and the total of 78 hours to reach MODE 3 and 12 hours for a second channel to be bypassed are justified in Reference 7.

K.1, K.2.1, and K.2.2

Condition K applies to the P-11 and P-12 interlocks.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock.

BASES

ACTIONS (continued)

Determination must be made within 1 hour and may be made by observation of the associated permissive annunciator window(s) (bistable status lights or computer checks). The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of these interlocks.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table stating that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.2.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is performed only on those channels that have channel parameter displays available. 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 two 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Agreement criteria are determined by the unit 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.

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

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. The time allowed for the testing (4 hours) is justified in Reference 5. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1 (excluding time constants which are verified during CHANNEL CALIBRATIONS). A successful test of any 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

For certain ESFAS Functions the required COT (SR 3.3.2.4 specified in Table 3.3.2-1) is modified by Notes (e) and (f). These Notes specify additional requirements for the affected instrument channels.

Note (e) specifies the following:

- If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service, and

- If the "as-found" instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

The evaluation of channel performance required by Note (e) involves an assessment to verify the channel will continue to behave in accordance with design basis assumptions, and to ensure confidence in the channel performance prior to returning the channel to service. In addition, if the "as found" trip setpoint value is non-conservative with respect to the Allowable Value, or is found to be outside of the two sided predefined acceptance criteria band on either side of the nominal trip setpoint, the affected channel will be evaluated under the corrective action program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Note (f) specifies the following:

- The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the nominal trip setpoint, or a value that is more conservative than the nominal trip setpoint; otherwise, the channel shall be declared inoperable, and

- The nominal trip setpoint and the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in a document incorporated by reference into the Updated Final Safety Analysis Report.

For BVPS, the document containing the nominal trip setpoint, the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band is the LRM.

For the ESFAS Functions with a COT modified by Note (f), the Note requires that the instrument channel setpoint be reset to a value within the "as left" setpoint tolerance band on either side of the nominal trip setpoint or to a value that is more conservative than the nominal trip setpoint. The conservative direction is established by the direction of the inequality sign applied to the associated Allowable Value. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisfied in order to protect the safety analysis limits. If the channel can not be reset to a value within the required "as left" setpoint tolerance band on either side of the nominal trip setpoint, or to a value that is more conservative than the nominal trip setpoint (if required based on plant conditions) the channel is declared inoperable and the applicable ACTION is entered.

For the ESFAS Functions with a COT modified by Notes (e) and (f), the "as found" and "as left" setpoint data obtained during COTs or CHANNEL CALIBRATIONS are programmatically trended to demonstrate that the rack drift assumptions used in the plant setpoint methodology are valid. If the trending evaluation determines that a channel is performing inconsistent with the uncertainty allowances applicable to the periodic surveillance test being performed, the channel is evaluated under the corrective action program. If the channel is not capable of performing its specified safety function, it is declared inoperable.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.5

SR 3.3.2.5 is the performance of a TADOT. This test is a check of the Undervoltage RCP Function. The Function is tested up to the SSPS logic circuit. A successful test of any 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay.

The Surveillance Frequency contained in the Surveillance Frequency Control Program specifies the separate Unit 1 and Unit 2 test Frequencies.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT. This test is a check of the P-4 interlock, Manual Actuation Functions and AFW pump start on trip of all MFW pumps. Each Manual Actuation Function is tested up to, and including, the master relay coils. A successful test of any 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical

BASES

SURVEILLANCE REQUIREMENTS (continued)

Specifications Surveillance Requirements. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of setpoints during the TADOT, since these Functions have no associated setpoints.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a CHANNEL CALIBRATION.

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

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

For certain ESFAS Functions the required CHANNEL CALIBRATION (SR 3.3.2.8 specified in Table 3.3.2-1) is modified by Notes (e) and (f). These Notes specify additional requirements for the affected instrument channels.

Note (e) specifies the following:

- If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service, and

- If the "as-found" instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

The evaluation of channel performance required by Note (e) involves an assessment to verify the channel will continue to behave in accordance with design basis assumptions, and to ensure confidence in the channel performance prior to returning the channel to service. In addition, if the "as found" trip setpoint value is non-conservative with respect to the

BASES

SURVEILLANCE REQUIREMENTS (continued)

Allowable Value, or is found to be outside of the two sided predefined acceptance criteria band on either side of the nominal trip setpoint, the affected channel will be evaluated under the corrective action program.

Note (f) specifies the following:

- The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the nominal trip setpoint, or a value that is more conservative than the nominal trip setpoint; otherwise, the channel shall be declared inoperable, and

- The nominal trip setpoint and the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in a document incorporated by reference into the Updated Final Safety Analysis Report.

For BVPS, the document containing the nominal trip setpoint, the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band is the LRM.

For the ESFAS Functions with a CHANNEL CALIBRATION modified by Note (f), the Note requires that the instrument channel setpoint be reset to a value within the "as left" setpoint tolerance band on either side of the nominal trip setpoint or to a value that is more conservative than the nominal trip setpoint. The conservative direction is established by the direction of the inequality sign applied to the associated Allowable Value. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisfied in order to protect the safety analysis limits. If the channel can not be reset to a value within the required "as left" setpoint tolerance band on either side of the nominal trip setpoint, or to a value that is more conservative than the nominal trip setpoint (if required based on plant conditions) the channel is declared inoperable and the applicable ACTION is entered.

For the ESFAS Functions with a CHANNEL CALIBRATION modified by Notes (e) and (f), the "as found" and "as left" setpoint data obtained during COTs or CHANNEL CALIBRATIONS are programmatically trended to demonstrate that the rack drift assumptions used in the plant setpoint methodology are valid. If the trending evaluation determines that a channel is performing inconsistent with the uncertainty allowances applicable to the periodic surveillance test being performed, the channel is evaluated under the corrective action program. If the channel is not capable of performing its specified safety function, it is declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.2.9

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time testing acceptance criteria are included in the Licensing Requirements Manual. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position). Each verification shall include at least one logic train such that both logic trains are verified at least once per the stated Frequency specified in the Surveillance Frequency Control Program.

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer functions set to one or by such means as utilizing a step change input with the resulting measured response time compared to the response time specified in the LRM. Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

- NOTE -

The following alternate means for verifying response times (i.e., summation of allocated times) is only applicable to Unit 2.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from:

BASES

SURVEILLANCE REQUIREMENTS (continued)

(1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," dated January 1996, provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," and WCAP-15413, "Westinghouse 7300A ASIC-Based Replacement Module Licensing Summary Report" provide the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter. WCAP-15413 provides bounding response times where 7300 cards have been replaced with ASICs cards.

Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 600 psig in the secondary side of the SGs.

BASES

REFERENCES

1. UFSAR Chapter 14 (Unit 1) and UFSAR Chapter 15 (Unit 2).

2. IEEE-279-1971.

3. Westinghouse Setpoint Methodology for Protection Systems, WCAP-11419, Rev. 6 (Unit 1) and WCAP-11366, Rev. 7 (Unit 2).

4. 10 CFR 50.49.

5. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

6. WCAP-14333-P-A, Rev. 1, “Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,” October 1998.

7. Amendment No. 282 (Unit 1) and Amendment No. 166 (Unit 2), December 29, 2008.

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit 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 Accidents (DBAs).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by unit specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO include Regulatory Guide 1.97 Type A and Category I variables as well as other Regulatory Guide 1.97 variables that provide important information for post accident monitoring. Certain Regulatory Guide 1.97 Type A and Category 1 variables, as determined by the Unit specific Regulatory Guide 1.97 analyses (Ref. 1), are not included in LCO 3.3.3 because other instrumentation required by this LCO provide the necessary information to the control room operators.

Type A variables are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

Category I variables are the key variables deemed risk significant because they are needed to:

Determine whether other systems important to safety are performing their intended functions,

Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release, and

BASES

BACKGROUND (continued)

Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1).

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures OPERABILITY of the required Regulatory Guide 1.97 variables so that the control room operating staff can:

Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA),

Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function,

Determine whether systems important to safety are performing their intended functions,

Determine the likelihood of a gross breach of the barriers to radioactivity release,

Determine if a gross breach of a barrier has occurred, and

Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk.

BASES

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A and other Regulatory Guide 1.97 instruments that provide important information for post accident monitoring.

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

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident. Therefore, where plant design permits, the two channels required OPERABLE by the LCO should be supplied from different trains of electrical power.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information. For some PAM Functions, Table 3.3.3-1 specifies one or three required channels. The following are exceptions to the two-channel requirement:

Three channels of steam generator (SG) wide range level instrumentation are required to be OPERABLE. Each SG has one installed wide range channel that assures the ability to monitor SG level during operating conditions when the level may not be in the normal range. In many accident analyses, two SGs are assumed to be available to provide the necessary heat removal capacity. The requirement for three OPERABLE channels of wide range level indication (one per SG) helps to assure adequate wide range SG level indication remains available (assuming one indication channel fails or a SG is faulted) to monitor SG level and support maintaining the necessary heat removal capacity.

Only one channel of high head safety injection (HHSI) total automatic injection header flow is required to be OPERABLE. The normal SI injection flow path (automatically initiated on an SI signal) has a single installed Regulatory Guide 1.97 flow instrument that indicates total SI flow in the control room. This indicator is used to confirm automatic SI flow initiation. The single HHSI total flow indication is adequate considering the alternate control room indications available to confirm the operation of the

BASES

LCO (continued)

SI System. An alternate method of verifying SI initiation can be provided by the High Head SI pump amperage indication, the High Head SI header pressure indication, and the SI automatic valve position indication.

Another exception to the two channel requirement is the Penetration Flow Path Containment Isolation Valve (CIV) Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. Active CIVs are those valves associated with an unisolated penetration and designed with control room indication per the Table 3.3.3-1 footnotes modifying the required channels of CIV position indication. The active CIVs addressed by this LCO only include valves designed to close on a Phase A or Phase B containment isolation signal. Valves that open on a Phase A or Phase B containment isolation signal are not required to have their position verified to confirm adequate containment isolation. This is sufficient to redundantly verify the isolation status of each required isolable penetration (required to be isolated during accident conditions) either via indicated status of the active valve or the reliability of CIVs without control room indication (i.e., automatic check valves and relief valves that are not dependent on an external power source or closure signal) or prior knowledge of a passive valve, or via closed system boundary status. If a normally active CIV is known to be closed and deactivated or open under administrative controls in accordance with the provisions of the CIV Technical Specification, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Type A and Category I variables are generally required to meet Regulatory Guide 1.97 Category I (Ref. 2) design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

The following are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1, 2, 3. <u>Power, Intermediate, and Source Range Neutron Flux</u>

Neutron Flux indication is provided to verify reactor shutdown. The three ranges are necessary to cover the full range of flux that may occur post accident.

The required channels of Source Range indication on Table 3.3.3-1 are modified by footnote (f) which provides an

BASES

LCO (continued)

exception that allows the source range neutron detectors to be de-energized above the P-6 Intermediate Range Neutron Flux Interlock. Source Range channel OPERABILITY, when the associated detector is de-energized, consists of being capable of performing its intended function once power is restored to the associated neutron detector. When the source range detectors are de-energized, the source range channels are also considered de-energized and SR 3.3.3.1 is not applicable. Similarly, the required channels for Intermediate and Power Range indication on Table 3.3.3-1 are modified by footnote (g) which provides an exception to the MODE 3 OPERABILITY requirement for this indication. In MODE 3, the Source Range channels are adequate to provide the required reactivity monitoring function. The Intermediate and Power Range indication channels serve to confirm reactor shutdown in a post reactor trip condition from power operation.

Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion. Neutron flux is classified as a Category 1 variable.

4, 5. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

RCS Hot and Cold Leg Temperatures are Type A and Category I variables provided for verification of core cooling and long term surveillance.

RCS hot and cold leg temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow termination of safety injection (SI), if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control.

In addition, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify the unit conditions necessary to establish natural circulation in the RCS.

6. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Type A and Category I variable provided for verification of core cooling and RCS integrity long term surveillance.

The LCO requirement for two OPERABLE indication channels can be met by using any combination of the RCS Pressure (Wide Range) indication channels or the RCS Pressure indication

BASES

LCO (continued)

channels associated with the Reactor Vessel Water Level Indicating System which also provide a qualified wide range RCS pressure indication.

RCS pressure can be used to verify delivery of SI flow to RCS from at least one train when the RCS pressure is below the pump shutoff head. RCS pressure may also be used to verify closure of manually closed spray line valves and pressurizer power operated relief valves (PORVs).

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI,
- to determine when to reset SI and shut off low head SI,
- to manually restart low head SI,
- as reactor coolant pump (RCP) trip criteria, and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization,
- to verify termination of depressurization, and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

A final use of RCS pressure is to determine whether to operate the pressurizer heaters.

BASES

LCO (continued)

RCS pressure is a Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

7. Reactor Vessel Water Level

Reactor vessel water level is classified as a Category 1 variable for Unit 1 and Category 2 variable for Unit 2.

Reactor Vessel Water Level is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

The Reactor Vessel Water Level Monitoring System provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

8. Containment Sump Water Level (Wide Range)

Containment Sump Water Level is provided for verification and long term surveillance of RCS integrity.

Containment Sump Water Level is used to determine:

- containment sump level accident diagnosis,
- when to begin the recirculation procedure (to confirm automatic initiation or if manual operation is necessary), and
- whether to terminate SI, if still in progress.

9. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) is classified as a Category 1 variable.

Containment Pressure (Wide Range) is provided for verification of RCS cooling and containment OPERABILITY (i.e., integrity).

BASES

LCO (continued)

The significant post accident use of containment pressure indication is to indicate the potential loss of a fission product boundary for the Emergency Action Levels in the E-Plan. Containment pressure is a key indicator in the declaration of a General Emergency level and the potential need for offsite protective action recommendations. The wide range containment pressure instrumentation provides an adequate range and sensitivity for this purpose.

10. Containment Area Radiation (High Range)

Containment Area Radiation (High Range) is classified as a Type A and Category 1 variable.

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to identify a loss of one or more fission product barriers.

11. Pressurizer Level

Pressurizer Level is classified as a Type A and Category 1 variable.

Pressurizer Level is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

12. Steam Generator Water Level (Wide Range)

SG Water Level (Wide Range) is classified as a Category 1 variable for Unit 1 and as a Type A and Category 1 variable for Unit 2.

SG Water Level (Wide Range) indication is provided to monitor operation of decay heat removal via the SGs. SG Water Level (Wide Range) indication is used to:

- identify the faulted SG following a steam generator tube rupture,

BASES

LCO (continued)

- verify that the intact SGs are an adequate heat sink for the reactor,
- determine the nature of the accident in progress (e.g., verify a steam generator tube rupture),
- verify unit conditions for the termination of SI during secondary side HELBs outside containment, and
- verify SG tubes are covered before terminating AFW to the faulted SG to assure iodine scrubbing and design basis iodine partitioning in the event of a steam generator tube rupture.

Controlling SG level to maintain a heat sink and the diagnosis of a steam generator tube rupture based on SG level are operator actions assumed in the design basis accident analysis for which no automatic actuation is provided. In addition, the PRA shows that SG Wide Range Level indication can be important to safety by providing information for the initiation of operator actions to establish bleed and feed for a loss of heat sink event.

13 a), b), c). Steam Generator (SG) Pressure

SG Pressure is classified as a Type A and Category 1 variable.

SG Pressure provides a target indication for RCS depressurization for the steam generator tube rupture accident to terminate the RCS inventory loss. In the event of a steam generator tube rupture accident, the EOPs instruct the operators to depressurize the RCS to a pressure below the secondary side pressure in the ruptured steam generator. RCS depressurization to a pressure less than the steam generator pressure terminates the RCS inventory loss and terminates the steam generator inventory gain, preventing overfill of the steam generator. The termination of the break flow is an operator action assumed in the design basis steam generator tube rupture analysis for which no automatic action is provided.

14. Primary Plant Demineralized Water Storage Tank (PPDWST) Level

The PPDWST level is classified as a Category 1 variable for Unit 1 and a Type A and Category 1 variable for Unit 2.

BASES

LCO (continued)

The PPDWST Level is provided to ensure water supply for auxiliary feedwater (AFW). The PPDWST provides the ensured safety grade water supply for the AFW System. The PPDWST Level indication is used for the diagnosis of the need to refill the tank to provide a long term steam generator heat sink for decay heat removal.

PPDWST Level is considered a Type A variable (for Unit 2) because the control room meter and annunciator are considered the primary indication used by the operator.

The PPDWST is the initial source of water for the AFW System. However, as the PPDWST is depleted, manual operator action is necessary to replenish the PPDWST or align suction to the alternate AFW pump suction supply.

15. Refueling Water Storage Tank (RWST) Level (Wide Range)

The RWST Level is classified as a Type A and Category 1 variable for Unit 1 and a Category 2 variable for Unit 2.

RWST Level provides an indication of the water inventory remaining for use by containment spray and safety injection for core cooling and containment cooling. No operator actions in the design basis accident analysis are based on the RWST Level indication. The switchover from the RWST to the containment sump is performed automatically.

In the event of an accident in which the RCS inventory losses are outside of containment (e.g., steam generator tube rupture or interfacing system LOCA), the remaining RWST level is an important indication for choosing the appropriate operator actions to maintain core cooling in the EOPs. The RWST Level is important in diagnosing the need for implementing RWST refill to maintain a sufficient inventory for long term core cooling following these events.

16. Penetration Flow Path Containment Isolation Valve (CIV) Position

Penetration Flow Path CIV Position indication is classified as a Category 1 variable for Unit 1 and a Category 2 variable for Unit 2. This indication is provided for verification of Containment Phase A and Phase B isolation. The E-Plan identifies that an elevated emergency action level should be declared following an accident in the event of a failure of automatic containment isolation.

BASES

LCO (continued)

This requirement only applies to containment isolation valves which receive a Phase A and Phase B containment isolation closure signal. This requirement is not applicable to valves that open on receipt of a Containment Phase A or B signal. When used to verify Phase A and Phase B isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active CIV in a containment penetration flow path, i.e., two total channels of CIV position indication for a penetration flow path with two active valves that have control room position indication. For containment penetrations with only one active CIV having control room indication, footnote (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 either via indicated status of the active valve with control room indication and the reliability of containment isolation valves without control room indication (i.e., automatic check valves and relief valves that are not dependent on an external power source or closure signal), or prior knowledge of a passive valve, or via closed system boundary status. If a normally active CIV is known to be closed and deactivated or open under administrative controls in accordance with the provisions of the CIV Technical Specification, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Footnote (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration 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. 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.

17 a), b), c), d) <u>Core Exit Temperature</u>

Core Exit Temperature is classified as a Category 1 variable for Unit 1 and a Type A and Category 1 variable for Unit 2.

Core Exit Temperature indication is provided for verification and long term surveillance of core cooling. The Core Exit Temperature indication provides information for the operators to initiate RCS depressurization following a steam generator tube rupture. Core Exit Temperature indication is important to safety because it provides information necessary to maintain subcooling

BASES

LCO (continued)

for RCS cooldown and depressurization following steam generator tube rupture and other small break LOCA events. It is also used as an indication for the transfer from the EOPs to the Severe Accident Management Guidance, where a greater focus is maintained on preserving the remaining fission product barriers.

Table 3.3.3-1 requires two OPERABLE channels of Core Exit Temperature per core quadrant. Footnote (c) to Table 3.3.3-1 requires a Core Exit Temperature channel to consist of two core exit thermocouples. Two sets of two thermocouples ensure that a single failure will not affect the ability to determine whether an inadequate core cooling condition exists.

18. Secondary Heat Sink Indication

Secondary Heat Sink Indication is comprised of two different types of indications (instruments). Footnote (d) to this Function explains that the two required channels per SG can be satisfied by using any combination of SG Water Level (Narrow Range) channels and Auxiliary Feedwater (AFW) Flow Channels such that two channels are OPERABLE for each SG.

SG Water Level (Narrow Range) is classified as a Type A and Category 1 variable. AFW Flow is classified as a Category 2 variable for Unit 1 and a Type A and Category 1 variable for Unit 2.

This indication provides confirmation of adequate SG inventory to ensure the required heat sink(s) are available. The availability of SG(s) for heat removal is important to safety to ensure adequate core cooling. This indication can also be used by the operator to confirm that the AFW System is in operation and delivering sufficient flow to each SG. AFW System initiation is important to safety because it provides information necessary for operator action to initiate alternate feedwater sources in the event of a failure of the AFW System.

19. High Head Safety Injection (SI) Flow

High Head Safety Injection (SI) Flow is classified as a Category 2 variable.

High Head SI Flow indication is used to confirm automatic safety injection initiation following a design basis accident. Therefore, the required flow indicator for this PAM Function is the total flow indicator installed in the automatic High Head SI flow path.

BASES

LCO (continued)

Failure to manually initiate SI flow when the automatic initiation fails can lead to a significant increase in core damage frequency. Operator action is based on the ECCS flow indication in the control room. Only high head safety injection is important for all accident sequences except the unlikely double-ended guillotine rupture of the largest reactor coolant pipe. Therefore, only the High Head SI Flow indication is required.

This instrumentation was not designed to meet Regulatory Guide 1.97 Category 1 or Type A requirements. Only a single channel is available and required OPERABLE for each unit. The requirement for a single OPERABLE channel of this indication is acceptable due to design requirements for this instrument (i.e., not Category 1) and the additional information available in the control room to confirm high head SI initiation. For example, if the total High Head SI Flow indication is not available, alternate methods of verifying SI initiation can be provided by the High Head SI pump amperage indication, the High Head SI header pressure indication, and the SI automatic valve position indication.

As only one channel of High Head SI Flow indication is required OPERABLE, the information associated with this Function on Table 3.3.3-1 is modified by footnote (e). Footnote (e) clarifies that Action Condition B is the only applicable Action Condition for Functions with only one required channel that can not be restored to OPERABLE status within the Completion Time specified in Action Condition A. As Footnote (e) and Condition B are in the Table column for Conditions referenced from Required Action D.1, this Table notation also clarifies that Action Conditions C, D, E, and F are not applicable to Functions that only require a single OPERABLE channel.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

BASES

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (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 assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies the immediate initiation of actions in Specification 5.6.5, which requires a written report to be submitted to the NRC within the following 14 days. This report discusses the results of the evaluation into the cause 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 likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). Required Action C.1 requires restoring one channel in the Function(s) 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.

BASES

ACTIONS (continued)

D.1

Condition D applies when the Required Action and associated Completion Time of Condition C are not met. Required Action D.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. 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 and E.2

If the Required Action and associated Completion Time of Condition C are not met and Table 3.3.3-1 directs entry into Condition E, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

F.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed and tested. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.5, in the Administrative Controls section of the TS. 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.

The following are examples of acceptable alternate indication methods for Reactor Vessel Water Level and Containment Area Radiation:

Reactor Vessel Water provides information to indicate whether the core cooling safety function is being accomplished. As such, the core exit temperature and subcooling (RCS Pressure and Temperature) indications may be used in lieu of Reactor Vessel Water indication.

BASES

ACTIONS (continued)

Radiation monitor RM-1RM-201 (Unit 1) and 2RMR-RQ202B (Unit 2) or a portable radiation monitor (with appropriate multiplier if necessary) can be used as an alternate method of indication for Containment Area Radiation High Range.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1 except as noted in SR 3.3.3.2.

SR 3.3.3.1

Performance of the CHANNEL CHECK ensures that a gross instrumentation failure 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 two 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.

In addition, it is not necessary to place a system or component in service that is not normally in service (e.g., initiate AFW flow to the SGs) in order to perform the required CHANNEL CHECK. In cases where the required instrumentation may be energized but only a single channel is available (e.g., HHSI Flow) or where there may be no flow (e.g., AFW Flow), the CHANNEL CHECK may be accomplished by comparing the indicated value to the known plant condition (e.g., zero flow). In the case of CIVs, the CHANNEL CHECK may be accomplished by comparing the indicated valve position to the known or expected valve position based on current plant conditions.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability as applicable. 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. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

SR 3.3.3.2

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. This SR is modified by Note 1 that excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." In addition, this SR is modified by Note 2 that states the CHANNEL CALIBRATION surveillance is not applicable to the Penetration Flow Path Containment Isolation Valve Position Indication Function. The required valve position indication channels are verified by a Trip Actuating Operational Test (TADOT) in lieu of a CHANNEL CALIBRATION. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Core Exit thermocouple sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.3

This Surveillance requires the performance of a TADOT. The TADOT is only required for the Penetration Flow Path Containment Isolation Valve Position Function on Table 3.3.3-1. The TADOT is adequate to verify the OPERABILITY of the required containment isolation valve position indication channels.

A Note modifies the SRs to specify that SR 3.3.3.3 is only applicable to the Penetration Flow Path Containment Isolation Valve Position Function. Due to the design of the instrument circuits involved, the TADOT, rather than the CHANNEL CALIBRATION, provides the more appropriate defined test to verify the OPERABILITY of these indication channels.

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

BASES

REFERENCES

1. Unit 1 Regulatory Guide 1.97 Submittals: (1) Duquesne Light Letter dated 10/13/86, Subject: Regulatory Guide 1.97, Revision 2, Supplemental Report (Complete RG 1.97 report attached), (2) Duquesne Light Letter dated 4/22/87, Subject: RG 1.97, Revision 2, Response to Interim Review Results, (Item 10, Type A classification of the Primary Plant Demineralized Water Storage Tank Level removed), (3) Duquesne Light Letter dated 12/18/89, Subject: Response to NRC RG 1.97 Concerns, (Page 4, A1 classification of AFW Flow removed).

   Unit 1 NRC Regulatory Guide 1.97 Safety Evaluation Reports (SERs): (1) NRC Letter dated 11/20/89, Subject: Completion of Review of Regulatory Guide 1.97 Conformance (TAC No. 51071), (2) NRC Letter dated 12/30/91, Subject: Emergency Response Capability - Conformance to Regulatory Guide 1.97 (TAC No. M75944), (3) NRC Letter dated 6/15/92, Subject: Emergency Response Capability - Conformance To Regulatory Guide 1.97 (TAC No. M75944), (4) NRC Letter dated 11/17/95, Subject: Conformance to Regulatory Guide 1.97, Revision 2, Post-Accident Neutron Flux Monitoring Instrumentation for BVPS Unit 1 (TAC No. M81201).

   Unit 2 Regulatory Guide 1.97 Submittal: UFSAR Table 7.5-1.

   Unit 2 NRC Regulatory Guide 1.97 SER: NUREG-1057, Supplement No. 1, Section 7.5, May 1986 (original Unit 2 SER).

2. Regulatory Guide 1.97, Rev. 2, December 1980.

3. NUREG-0737, Supplement 1, "TMI Action Items."

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient indications and controls to maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator (SG) atmospheric dump valves (ADVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish control utilizing the Remote Shutdown System. The Remote Shutdown System indications and controls necessary to maintain the unit in a safe shutdown condition (MODE 3) are specified in Table B 3.3.4-1 and are physically located on the Emergency Shutdown Panels (PNL-SHUTDN for Unit 1 and PNL-2SHUTDN for Unit 2). The unit automatically reaches MODE 3 following a unit trip and can be maintained safely in MODE 3 for an extended period of time. Plant procedures assure the reactor is manually tripped and safely shutdown prior to transferring control to the Emergency Shutdown Panel.

The OPERABILITY of the remote shutdown control and indication functions ensures there is sufficient information available on selected unit parameters to maintain the unit in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to maintain the unit in a safe condition in MODE 3.

There are no specific design basis accident safety analysis assumptions (i.e., single active failures) that would require redundant Remote Shutdown System indications or controls be maintained OPERABLE by the Technical Specifications. Therefore, Table B 3.3.4-1 only specifies that a single channel of each indication and control function be OPERABLE in order to meet the requirements of the LCO.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The criteria governing the design and specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

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

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements for the indications and controls necessary to maintain the unit in MODE 3 from the Emergency Shutdown Panels (PNL-SHUTDN for Unit 1 and PNL-2SHUTDN for Unit 2). The indications and controls required are listed in Table B 3.3.4-1. Each control channel specified in Table B 3.3.4-1 consists of both the control switch and associated transfer switch if applicable.

The controls, indications, and transfer switches are required for:

- Core reactivity control,
- RCS pressure control,
- Decay heat removal via the AFW System and the SG ADVs,
- RCS inventory control via charging flow, and
- Safety support systems for the above Functions, including Component Cooling Water, Unit 1 River Water, and Unit 2 Service Water.

A Function of a Remote Shutdown System is OPERABLE if all indication and control channels needed to support the Remote Shutdown System Function are OPERABLE. However, not all indication and control circuits associated with the systems identified in Table B 3.3.4-1 are required OPERABLE in order to support the required Remote Shutdown System Function. Table B 3.3.4-1 only specifies 1 required channel for each indication and control instrument associated with each Remote Shutdown System Function. For example, the capability to remotely operate a single AFW pump and control its flow and the control of one associated SG ADV provide the necessary control channels to accomplish the decay heat removal Function specified in Table B 3.3.4-1. All the AFW pump and flow controls do not have to be OPERABLE to accomplish the decay heat removal Function required OPERABLE by the LCO. Similarly, the control for a single letdown orifice isolation valve is sufficient to meet the requirement of the RCS Inventory Function for 1 channel of letdown flow control.

BASES

LCO (continued)

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

APPLICABILITY

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

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

A Remote Shutdown System Function is inoperable when 1 or more required channel(s) of indication or control are inoperable. The required channels of indication and control for each Remote Shutdown System Function are specified on Table B 3.3.4-1.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System are inoperable. This includes the control and transfer switches for any required Function.

The Required Action is to restore the required Function 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.

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

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

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If the channels are within the criteria, it is an indication that the channels are OPERABLE. 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 indication channels which are normally energized. In addition, it is not necessary to place a system or component in service that is not normally in service (e.g., initiate AFW flow to the SGs) in order to perform the required CHANNEL CHECK of a Remote Shutdown System indication channel. In cases where the required instrumentation may be energized but only a single channel is available or where there may be no flow (e.g., AFW Flow), the CHANNEL CHECK may be accomplished by comparing the indicated value to the known plant condition (e.g., zero flow).

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

SR 3.3.4.2

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

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detector~~s~~ (RTD) sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

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

SR 3.3.4.3

SR 3.3.4.3 verifies each required Remote Shutdown System control circuit and transfer switch 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 unit can be maintained in MODE 3 from the Emergency Shutdown Panels (PNL-SHUTDN for Unit 1 and PNL-2SHUTDN for Unit 2).

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

Table B 3.3.4-1 (page 1 of 1)
Remote Shutdown System Indications and Controls

Emergency Shutdown Panels
PNL-SHUTDN (Unit 1) and PNL-2SHUTDN (Unit 2)

REMOTE SHUTDOWN SYSTEM FUNCTION INDICATIONS AND CONTROLS	REQUIRED NUMBER OF CHANNELS
1. Reactivity Control Function	
a. Source Range Neutron Flux (indication)	1[(a)]
b. Boric Acid Transfer Pump (control)	1
2. Reactor Coolant System (RCS) Pressure Control Function	
a. Pressurizer Pressure (indication) or RCS Wide Range Pressure (indication) (Unit 2 only)	1
b. Pressurizer heater (control)	1
3. Decay Heat Removal via Steam Generators (SGs) Function	
a. RCS Hot Leg Temperature (indication)	1
b. RCS Cold Leg Temperature (indication)	1
c. SG Pressure (indication)	1/SG
d. SG Level (indication)	1/SG
e. AFW Flow (indication)	1/SG
f. SG Atmospheric Dump Valve (control) or Residual Heat Release Valve (control) (Unit 2 only)	1
g. AFW pump (control)	1
h. AFW Flow (control)	1
4. RCS Inventory Control Function	
a. Pressurizer Level (indication)	1
b. Charging Pump (control)	1
c. Charging Flow (control)	1
d. Letdown Flow (control)	1
5. Support Systems	
a. Component Cooling Water pump (control)	1
b. River Water pump (control) (Unit 1 only)	1
c. Service Water pump (control) (Unit 2 only)	1

(a) Source Range neutron detectors are not required to be energized above the P-6 Intermediate Range Neutron Flux Interlock.

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. The LOP instrumentation ensures a reliable source of emergency power by providing the following Functions: 1) An automatic DG start on emergency bus undervoltage, and 2) Separation of the emergency buses on undervoltage and degraded voltage conditions.

Loss of Voltage Protection

Unit 1

The Unit 1 loss of voltage protection consists of two relays for each of the 4160 V emergency buses. One relay actuates to open the normal supply breakers for the associated emergency buses (bus separation). The other loss of voltage relay provides a start signal for the DG associated with the bus. Both loss of voltage relays have the same nominal trip setpoint and Allowable Value (with different time delays).

Unit 2

The Unit 2 loss of voltage protection consists of three relays for each 4160 V emergency bus. Two relays on each bus actuate to open the normal supply breakers for the associated emergency buses (with a two-out-of-two logic per bus) to provide the bus separation function. The other loss of voltage relay provides a start signal for the associated DG. All three loss of voltage relays have the same nominal trip setpoint and Allowable Value (with different time delays).

Degraded Voltage Protection

In addition to the loss of voltage protection, degraded voltage protection for both Units is provided by two relays on each 4160 V emergency bus and two relays on each 480 V emergency bus. The two relays on each bus actuate upon a reduced voltage condition that exists for an extended time. The relays actuate (in a two-out-of-two logic per bus) to open the normal supply breakers and separate the affected emergency bus from the degraded voltage supply. The two-out-of-two logic helps prevent a spurious relay actuation from causing bus separation.

The Unit 1 and Unit 2 LOP instrumentation is described in UFSAR Chapter 8 (Ref. 1).

BASES

BACKGROUND (continued)

The Allowable Value in conjunction with the nominal trip setpoint and LCO establishes the threshold for the LOP instrumentation capability to provide the required loss of voltage and degraded voltage protection that assures a reliable source of emergency power. The nominal trip setpoints are specified in the Licensing Requirements Manual (LRM). The Allowable Value is considered a limiting value such that a channel is OPERABLE if the setpoint is found to satisfy the applicable Allowable Value requirements specified in Table 3.3.5-1 during the CHANNEL CALIBRATION. Note that although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to within the established calibration tolerance band of the setpoint in accordance with uncertainty assumptions stated in the referenced setpoint methodology, (as-left-criteria) and confirmed to be operating within the statistical allowances of the uncertainty terms assigned.

Allowable Values and LOP DG Start Instrumentation Setpoints

The allowances used to develop the nominal trip setpoints for the loss of voltage and degraded voltage relays are described in the unit specific setpoint methodology (Ref. 2). The selection of the nominal trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account.

Setpoints adjusted consistent with the requirements of the Allowable Value ensure that the operation of the LOP Instrumentation will be acceptable, providing the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed.

Allowable Values are specified for each Function in Table 3.3.5-1. Nominal trip setpoints are specified in the LRM. The nominal trip setpoints are selected to ensure that the setpoint measured by the surveillance procedure does not exceed the Allowable Value if the relay is performing as required. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint methodology (Ref. 2).

APPLICABLE SAFETY ANALYSES

The LOP instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has

BASES

APPLICABLE SAFETY ANALYSIS (continued)

historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 3, in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay where applicable.

The LOP instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP instrumentation requires that the loss of voltage and degraded voltage instrument channels specified in Table 3.3.5-1 be OPERABLE in MODES 1, 2, 3, and 4 when the LOP instrumentation supports safety systems associated with the ESFAS. In MODES 5, 6, and during fuel movement, the LOP instrumentation must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure a reliable source of emergency power is available when needed. A channel is OPERABLE provided the trip setpoint "as-found" value satisfies the applicable Allowable Value requirements specified in Table 3.3.5-1 and provided the trip setpoint "as-left" value is adjusted to a value within the "as-left" calibration tolerance band of the nominal trip setpoint. A trip setpoint may be set more conservative than the nominal trip setpoint as necessary in response to plant conditions provided that the ± calibration tolerance band remains the same and the Allowable Value is administratively controlled accordingly in the conservative direction to meet the assumptions of the setpoint methodology. The conservative direction is established by the direction of the inequality applied to the Allowable Value. Loss of the LOP Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. For example, during the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

BASES

APPLICABILITY

The LOP Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5, 6, and during fuel movement is required whenever the required DG must be OPERABLE so that it can perform its function for a loss of voltage or degraded voltage condition on an emergency bus.

ACTIONS

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function specified in Table 3.3.5-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to all LOP instrument functions specified in Table 3.3.5-1. Condition A addresses the situation where one or more channels for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.5-1 and to take the applicable Required Actions for the LOP functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1

Condition B applies to the LOP Functions with one loss of voltage or one degraded voltage channel per bus inoperable. The Condition is applicable to a single inoperable channel on one bus or a single inoperable channel on each bus.

If one channel is inoperable, Required Action B.1 requires that channel to be placed in trip within 72 hours. With a channel in trip, the LOP instrumentation channels are configured to provide a one-out-of-one logic to initiate the LOP protection function.

A Note is added to allow bypassing an inoperable channel for up to 12 hours for surveillance testing of other channels provided the corresponding instrument channels, electrical bus, and DG in the other

BASES

ACTIONS (continued)

train are OPERABLE. This allowance is made where bypassing the channel does not cause an actuation and where the other electrical train remains OPERABLE to supply emergency power if required.

The specified Completion Time and time allowed for bypassing one channel are justified in Reference 4.

C.1

Condition C applies when more than one loss of voltage or more than one degraded voltage channel per bus are inoperable. The Condition is applicable to two inoperable channels on one bus or two inoperable channels on each bus.

Required Action C.1 requires restoring one channel per bus to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP instrument actuation during this interval.

D.1

Condition D applies when one loss of voltage channel per bus is inoperable and is applicable only to those LOP Functions on Table 3.3.5-1 with a single loss of voltage channel per bus. The Condition is applicable to a single inoperable channel on one bus or a single inoperable channel on each bus.

Required Action D.1 requires restoring the inoperable channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring a LOP instrument actuation during this interval.

E.1

Condition E applies to each of the LOP instrument Functions when the Required Action and associated Completion Time for Condition A, B, C, or D are not met.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, "AC Sources - Shutdown," for the DG made inoperable by failure of the LOP instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. A successful test of any 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that excludes verification of setpoint from the TADOT. The SR applies to the loss of voltage and degraded voltage relays for the 4160 V and 480 V emergency buses and setpoint verification requires removal of the relay and a bench calibration. Therefore, relay calibration and setpoint verification are accomplished during the CHANNEL CALIBRATION.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as specified in the LRM.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. For Unit 1 only, the time delay specified for the 4160 V emergency bus loss of voltage DG start relay, includes auxiliary relay times.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. The response time acceptance criteria for instrument channels with a required response time are specified in the LRM. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor, to the point at which the equipment reaches the required functional state. Response time may be verified by any series of sequential, overlapping or total channel measurement such that the entire response time is measured.

The Bases for Surveillance Requirement 3.3.2.9 in LCO 3.3.2, "ESFAS Instrumentation" contains a more detailed description of how the required response time verification may be accomplished. The SR 3.3.2.9 Bases is applicable to SR 3.3.5.3 including the Unit 2 option to use the summation of allocated response times.

The final actuation device response time, which makes up the bulk of the total response time, is included in the verification of each channel. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Unit 1 and Unit 2 UFSAR, Chapter 8.

2. Westinghouse Setpoint Methodology for Protection Systems, WCAP-11419, Rev. 6 (Unit 1) and WCAP-11366, Rev. 7 (Unit 2).

3. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.

4. Amendment No. 282 (Unit 1) and Amendment No. 166 (Unit 2), December 29, 2008.

B 3.3 INSTRUMENTATION

B 3.3.6 Unit 2 Containment Purge and Exhaust Isolation Instrumentation

BASES

BACKGROUND

The Unit 2 containment purge and exhaust isolation instrumentation closes the 42 inch containment isolation valves in the Purge and Exhaust System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of a fuel handling accident involving recently irradiated fuel.

Two gaseous (Xe-133) radiation monitoring channels (2HVR-RQ104A&B) are provided as input to the containment purge and exhaust isolation. The radiation monitors have a measurement range of 10^{-6} to 10^{-1} μCi/cc.

The Purge and Exhaust System has inner and outer containment isolation valves in its supply and exhaust ducts. A high radiation signal from the 2HVR-RQ104A gaseous radiation monitor closes the outer isolation valves in each penetration and a high radiation signal from the 2HVR-RQ104B gaseous monitor closes the inner isolation valves in each penetration.

In addition to the automatic closure provided by the high radiation signal each containment purge and exhaust isolation valve may be closed manually by its individual control switch.

APPLICABLE SAFETY ANALYSES

During refueling operations, the postulated event that results in the most severe radiological consequences is a fuel handling accident (Ref. 1). The limiting fuel handling accident analyzed in Reference 1, includes dropping a single irradiated fuel assembly and handling tool (conservatively estimated at 2500 pounds) directly onto another irradiated fuel assembly resulting in both assemblies being damaged. The analysis assumes a 100-hour decay time prior to moving irradiated fuel.

The applicable limits for offsite and control room dose from a fuel handling accident are specified in 10 CFR 50.67. Standard Review Plan, Section 15.0.1, Rev 0 (Ref. 2) provides an additional offsite dose criteria of 6.3 rem total effective dose equivalent (TEDE) for fuel handling accidents.

The water level requirements of LCO 3.9.6, "Refueling Cavity Water Level," in conjunction with a minimum decay time of 100 hours prior to irradiated fuel movement, ensure that the resulting offsite and control room dose from the limiting fuel handling accident is within the limits required by 10 CFR 50.67 and within the acceptance criteria of

BASES

APPLICABLE SAFETY ANALYSES (continued)

Reference 2 without the need for containment purge and exhaust isolation.

Therefore, the instrumentation requirements of LCO 3.3.6 "Containment Purge and Exhaust Isolation Instrumentation" are only applicable during refueling operations involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). Current requirements based on the decay time of the fuel prevent the movement of recently irradiated fuel. However, the requirements for containment purge and exhaust isolation instrumentation are retained in the Technical Specifications in case these requirements are necessary to support fuel movement involving recently irradiated fuel.

The containment purge and exhaust isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Purge and Exhaust Isolation, listed in Table 3.3.6-1, is OPERABLE for Unit 2.

The LCO is modified by a Note that states "This specification is only applicable to Unit 2." Unit 1 relies on filtration of the Containment Purge and Exhaust System effluent by an OPERABLE train of Supplemental Leak Collection and Release System (SLCRS) instead of isolation. Unit 1 must rely on filtration due to the design of the Unit 1 Containment Purge and Exhaust System ductwork where the radiation monitors are located. The Unit 1 ductwork is not designed to withstand a seismic event (Ref. 3).

1. Manual Initiation

   The LCO requires one manual initiation channel per Purge and Exhaust System isolation valve to be OPERABLE. Containment Purge and Exhaust Isolation may be initiated at any time by using the individual valve control switches in the control room. Each channel consists of a manual switch and interconnecting circuits to the valve actuator.

2. Containment Radiation

   The LCO specifies two required channels of gaseous radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge and Exhaust Isolation remains OPERABLE.

BASES

LCO (continued)

The required gaseous monitors are an in-line type and are mounted directly in the exhaust ductwork. An OPERABLE radiation monitor channel consists of the monitor and includes any associated circuitry necessary to provide the required isolation function.

APPLICABILITY

The containment purge and exhaust isolation instrument requirements are applicable during movement of recently irradiated fuel assemblies or the movement of fuel assemblies over recently irradiated fuel assemblies within containment because this is when there is a potential for the limiting fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements (including the purge and exhaust isolation valves) are addressed by LCO 3.6.3, "Containment Isolation Valves" and LCO 3.6.1, "Containment OPERABILITY." In MODES 5 and 6, when movement of irradiated fuel assemblies within containment is not being conducted, the potential for a fuel handling accident does not exist. Additionally, due to radioactive decay, a fuel handling accident that does not involve recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) will result in doses that are well within the guideline values specified in 10 CFR 50.67 even without containment closure capability. Therefore, under these conditions no requirements are placed on the Containment Purge and Exhaust Isolation Instrumentation.

Although movement of recently irradiated fuel is not currently permitted, the requirements for containment purge and exhaust isolation instrumentation are retained in the Technical Specifications in case these requirements are necessary to support the assumptions of a safety analysis for fuel movement involving recently irradiated fuel consistent with the guidance of Ref. 4.

ACTIONS

If the Trip Setpoint is less conservative than specified in Table 3.3.6-1, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

BASES

ACTIONS (continued)

A.1

Condition A applies to the failure of one containment purge isolation radiation monitor channel. The 4 hours allowed to restore the affected channel is justified by the low likelihood of events occurring during this interval, and recognition that the remaining channel will isolate the purge and exhaust lines on high radiation.

B.1 and B.2

Condition B applies to all Containment Purge and Exhaust Isolation Functions. It addresses the failure of multiple radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1. If one or more manual initiation channels are inoperable, or two radiation monitor channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place and maintain containment purge and exhaust isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. The Completion Time for these Required Actions is Immediately.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Purge and Exhaust Isolation Functions.

SR 3.3.6.1

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

Agreement criteria are determined by the unit 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 LCO required channels.

SR 3.3.6.2

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of any 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications Surveillance Requirements. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This test verifies the capability of the instrumentation to provide the containment purge and exhaust system isolation. The setpoint shall be left consistent with the current unit specific calibration procedure tolerance.

SR 3.3.6.3

SR 3.3.6.3 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. Each Manual Actuation Function is tested for each valve. The test includes actuation of the end device (i.e., valve cycles).

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

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

SR 3.3.6.4

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

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

BASES

REFERENCES

1. Unit 2 UFSAR 15.7.4.
2. NUREG-0800, Section 15.0.1, Rev. 0, July 2000.
3. NRC Safety Evaluation Report for Unit 1 Amendment 23, 12/12/79.
4. NUREG-1431, "Standard Technical Specifications for Westinghouse Plants," Rev. 2, April 2001.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Emergency Ventilation System (CREVS) Actuation Instrumentation

BASES

BACKGROUND

The CREVS provides an enclosed common control room environment from which both units can be operated following an uncontrolled release of radioactivity. During normal operation, the Control Room Ventilation System recirculates the control room air and provides unfiltered makeup air and cooling. Upon receipt of a CREVS actuation signal from either unit, the Unit 1 and 2 control room ventilation intake and exhaust ducts are isolated to prevent unfiltered makeup air from entering the control room. In addition, the CREVS actuation signal from either unit will also automatically start one Unit 2 CREVS fan to provide filtered makeup air to pressurize the control room. If the preferred Unit 2 CREVS fan does not start, the backup Unit 2 fan will automatically start. Unit 1 may take credit for the operation of one or both of the Unit 2 CREVS fans and filters. One of the two Unit 1 CREVS fans and single filter must be manually aligned and placed in service if required. Once the control room ventilation intake and exhaust ducts are isolated, and the CREVS fan is providing filtered makeup, control room ventilation is in the emergency pressurization mode of operation. The CREVS is described in the Bases for LCO 3.7.10, "Control Room Emergency Ventilation System."

The CREVS actuation instrumentation consists of redundant control room area radiation monitors for each unit, Containment Isolation - Phase B (CIB) signal from each unit, and two train related manual switches (pushbuttons) in each unit's control room. A high radiation signal from the radiation monitors in either unit, a CIB from either unit, or manual switch actuation from either unit such that both trains of CREVS receive an actuation signal, will initiate the CREVS actuation sequence described above. The CIB Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations. The CREVS acts to terminate the supply of unfiltered outside air to the control room, initiate intake air filtration, and pressurize the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

The applicable safety analyses for all design basis accidents considered in MODES 1, 2, 3, and 4 (except LOCA) assume manual initiation of the emergency pressurization mode of operation of control room ventilation (i.e., control room ventilation isolation, filtered makeup, and

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressurization). The LOCA accident analysis assumes an automatic Control Room Ventilation System isolation on a CIB signal and subsequent manual initiation of a CREVS fan for filtered makeup and pressurization of the control room. Although the CIB signal will automatically start a CREVS fan and filtered flow path, a 30-minute delay to allow for manual initiation of a CREVS fan and filtered flow path is specifically assumed in all analyses to permit the use of a Unit 1 CREVS fan and filtration flow path which require manual operator action to place in service (Ref. 1).

The current safety analyses do not assume the control room area radiation monitors provide a CREVS actuation signal for any design basis accident. However, requirements for the radiation monitors to be OPERABLE are retained in case the monitors are required to support the assumptions of a fuel handling accident analysis for the movement of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) or the movement of fuel over recently irradiated fuel consistent with the guidance of Ref. 2.

The CREVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CREVS is OPERABLE.

1. Manual Initiation

The LCO requires two trains OPERABLE. The operator can initiate the CREVS at any time by using either of two switches (pushbuttons) in the control room. This action will cause actuation of all components in the same manner as a single train of the automatic actuation signals (i.e., isolate control room ventilation and start one Unit 2 CREVS fan aligned for filtration and pressurization).

However, when Unit 1 is relying on the Unit 1 CREVS train, as one of the two required trains, only one of the Unit 1 manual pushbuttons is required to start a Unit 2 Fan, but both Unit 1 pushbuttons must be capable of isolating the control room. In this case, the Unit 1 requirement (on Table 3.3.7-1) for two trains of manual initiation is met by one train of manual initiation that is capable of isolating the control room and starting a Unit 2 fan and one train of manual initiation that is capable of isolating the control room. The capability to manually place the Unit 1 CREVS fan and filtered flow path in service is addressed by the OPERABILITY requirements for the Unit 1 CREVS equipment contained in LCO 3.7.10, "Control Room Emergency Ventilation System."

BASES

LCO (continued)

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each manual initiation train consists of a switch (pushbutton) in the control room, and the interconnecting wiring to the actuating relays.

2. Control Room Radiation

The LCO specifies two required Control Room Area Radiation Monitors to ensure that the radiation monitoring instrumentation necessary to initiate the CREVS remains OPERABLE.

The required Unit 1 radiation monitors are designated RM-1RM-218 A & B with a measurement range of 10^{-2} to 10^{3} mR/hr. The required Unit 2 radiation monitors are designated 2RMC-RQ201 & 202 with a measurement range of 10^{-2} to 10^{3} mR/hr.

3. Containment Isolation Phase B (CIB)

Refer to LCO 3.3.2, Function 3.b, for all initiating Functions and requirements.

If one or more of the CIB functions becomes inoperable in such a manner that only the CREVS function is affected, the Conditions applicable to their CIB function need not be entered. The less restrictive Actions specified for inoperability of the CREVS Functions specify sufficient compensatory measures for this case.

APPLICABILITY

The CREVS manual actuation instrumentation must be OPERABLE in MODES 1, 2, 3, and 4 to provide the required CREVS initiation assumed in the applicable safety analyses. In MODES 5 and 6, when no fuel movement involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) is taking place, there are no requirements for CREVS instrumentation OPERABILITY consistent with the safety analyses assumptions applicable in these MODES. In addition, both manual and radiation monitor instrument channels are required OPERABLE when moving recently irradiated fuel or moving fuel over recently irradiated fuel. Although the movement of recently irradiated fuel is not currently permitted, these requirements are retained in the Technical Specifications in case the CREVS instrumentation is necessary to support the assumptions of a safety analysis for fuel movement involving recently irradiated fuel, consistent with the guidance of Reference 2.

BASES

APPLICABILITY (continued)

The Applicability for the CREVS actuation on the ESFAS CIB Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the CIB Function Applicability.

ACTIONS

If the Trip Setpoint is less conservative than required in Table 3.3.7-1, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the radiation monitor channel Functions, and the manual initiation train Functions.

If one train is inoperable, or one radiation monitor channel is inoperable in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10. If the channel/train cannot be restored to OPERABLE status, one CREVS train must be placed in the emergency pressurization mode of operation as described in LCO 3.7.10 bases. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

B.1 and B.2

Condition B applies to the failure of two radiation monitor channels, or two manual trains. The first Required Action is to place one CREVS train in the emergency pressurization mode of operation immediately. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. The applicable Conditions and Required Actions of LCO 3.7.10 must also be entered for the remaining CREVS train made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.10.

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

Condition D applies when the Required Action and associated Completion Time for Condition A or B have not been met when moving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) or fuel assemblies over recently irradiated fuel. Fuel movement involving recently irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require CREVS actuation.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CREVS Actuation Functions.

SR 3.3.7.1

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

Agreement criteria are determined by the unit 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 LCO required channels.

SR 3.3.7.2

A COT is performed on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CREVS actuation. A successful test of any 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications Surveillance Requirements. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.3

SR 3.3.7.3 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. Each Manual Actuation Function is tested. A successful test of any 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications Surveillance Requirements. The test may either include actuation of the end device (i.e., dampers close, and fan starts, etc.), or test up to the point of overlap with other tests that demonstrate actuation of the end devices.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.4

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

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

REFERENCES

1. Unit 1 UFSAR Table 14.1-1A and Unit 2 UFSAR Table 15.0-13.

2. NUREG-1431, "Standard Technical Specifications for Westinghouse Plants," Rev. 2, April 2001.

B 3.3 INSTRUMENTATION

B 3.3.8 Boron Dilution Detection Instrumentation

BASES

BACKGROUND

The purpose of the Boron Dilution Detection Instrumentation is to monitor core reactivity and provide indication of a boron dilution event in the Reactor Coolant System (RCS) when the reactor is in a shutdown condition (i.e., MODES 3, 4, and 5) with all rods fully inserted and the Rod Control System incapable of rod withdrawal.

The required Boron Dilution Detection Instrumentation consists of one of the two channels of OPERABLE source range instrumentation. The requirement for an OPERABLE source range channel ensures the capability to monitor core reactivity and detect a boron dilution event. In order to promptly detect a boron dilution event in MODE 3, the required source range instrumentation must provide both visual and audible (count rate) indication. The audible count rate helps to assure the prompt detection of an ongoing dilution event. In MODES 4 and 5, a boron dilution event is prevented by the requirements of LCO 3.1.8, "Unborated Water Source Isolation Valves." LCO 3.1.8 requires that unborated water source isolation valves be verified closed which precludes a dilution event (Ref. 1). Therefore, in MODES 4 and 5 the single channel of source range instrumentation required OPERABLE by this LCO is only used to monitor core reactivity and is required to provide visual indication only. As the requirements of LCO 3.1.8 preclude a boron dilution event in MODES 4 and 5, the audible count rate is not required for prompt detection of an inadvertent boron dilution in these MODES.

For Unit 1, two spare source range detectors are installed (N-33 and N-34). These alternate detectors may be substituted for detectors (N-31 and N-32). For Unit 2, alternate detectors (i.e., Gamma-Metrics NE-52A and NE-52B) may also be used to meet the requirements of the LCO. The alternate detectors must be capable of providing the required indication (described above) in order to be considered OPERABLE.

APPLICABLE SAFETY ANALYSES

The Boron Dilution Detection Instrumentation specifies the OPERABILITY of instrumentation necessary to detect an inadvertent boron dilution event and monitor core reactivity.

The primary means of preventing an inadvertent boron dilution event during MODES 4 and 5 is the requirements of LCO 3.1.8. LCO 3.1.8 provides assurance the unborated water sources are maintained isolated to prevent dilution of the RCS (Ref. 1). In MODES 4 and 5, the requirement for an OPERABLE source range channel only serves to

BASES

APPLICABLE SAFETY ANALYSES (continued)

ensure the capability to monitor changes in core reactivity is maintained available. In MODES 4 and 5, no specific safety analysis assumptions are associated with the capability to monitor core reactivity. However, the capability to directly monitor core reactivity with the source range instrumentation provides valuable assurance that the core continues to be maintained in a safe condition.

In MODE 3, the requirements of LCO 3.1.8 to maintain unborated water source valves isolated is not applicable. In addition, with all rods fully inserted and the Rod Control System is incapable of rod withdrawal, the trip functions of LCO 3.3.1, "Reactor Trip System" are not required OPERABLE. Therefore, in this plant condition, an OPERABLE source range channel that includes both visual and audible (count rate) indication is required to ensure prompt indication of an inadvertent boron dilution. The prompt notification of a boron dilution event in progress (via an increasing audible count rate) allows time for operator action to stop the dilution prior to criticality.

The Boron Dilution Detection Instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

LCO 3.3.8 specifies the OPERABILITY requirements for the instrumentation necessary to detect a boron dilution event and monitor core reactivity. In the applicable plant condition (all rods fully inserted and the Rod Control System incapable of rod withdrawal) the specified instrumentation only provides a core reactivity monitoring function and is not required to provide a reactor trip function. Therefore, in MODE 3, a single OPERABLE source range channel with both visual and audible (count rate) indication is required to provide prompt indication of an inadvertent boron dilution. In MODES 4 and 5, a single OPERABLE source range channel with visual indication is required to provide the necessary core reactivity monitoring function. In MODE 3 operation, with the Rod Control System capable of rod withdrawal, the requirements of LCO 3.3.1, "Reactor Trip System Instrumentation," are applicable and the requirements of LCO 3.3.8, including the audible count rate, are not applicable and no longer required to provide protection from an inadvertent boron dilution.

An alternate source range detector may be used to meet the requirements of the LCO as long as it is capable of providing the required indication(s) described above.

BASES

APPLICABILITY

The Boron Dilution Detection Instrumentation must be OPERABLE in MODES 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal. The requirements of this LCO ensure the capability to detect an inadvertent boron dilution of the RCS in MODE 3 and provide a means for monitoring core reactivity in MODES 4 and 5.

In MODES 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted the nuclear instrumentation requirements of LCO 3.3.1, "Reactor Trip System Instrumentation," are applicable and specify that two source range channels must be OPERABLE with reactor trip capability. In addition, in MODE 3, operation with the Rod Control System capable of rod withdrawal is transitory in preparation for startup operations and manually controlled involving the close monitoring of core reactivity and dilution operations by the operating staff. Therefore, in MODE 3, with the Rod Control System capable of rod withdrawal, the requirements of LCO 3.3.8, including the audible count rate, are no longer applicable and not required to provide protection from an inadvertent boron dilution.

In MODES 4, 5, or 6 a dilution event is precluded by the requirements of LCO 3.1.8, " Unborated Water Source Isolation Valves" (Ref. 1). Therefore, in MODES 4, 5, and 6, the required source range instrumentation provides an indication of core reactivity. LCO 3.9.2, "Nuclear Instrumentation" addresses the source range instrument requirements in MODE 6.

During MODE 1 operation, the source range instrumentation is normally de-energized. In MODE 1, the Overtemperature ΔT Trip Function required OPERABLE in LCO 3.3.1, "Reactor Trip System," and the requirements of LCO 3.1.6, "Control Bank Insertion Limits" provide for the necessary protection from, and detection of, an inadvertent boron dilution event at power (Ref. 1).

In MODE 2, the RCS is intentionally diluted and the rods withdrawn in order to achieve criticality and power operation. Operation in MODE 2 is transitory and manually controlled involving the close monitoring of core reactivity and dilution operation by the operating staff. As such, an inadvertent dilution of the RCS in this mode of operation is unlikely. However, in order to increase power during startup, the source range Trip Function required OPERABLE by LCO 3.3.1, must be manually blocked to prevent a reactor trip upon power escalation. If power escalation proceeds in an uncontrolled manner (due to inadvertent dilution) the Source Range Trip would not be blocked and would cause a reactor shutdown and provide protection and detection of an inadvertent dilution (Ref. 1).

BASES

ACTIONS

A.1 and A.2

With the required channel inoperable, the initial action is to suspend all operations involving positive reactivity additions immediately. This includes withdrawal of control or shutdown rods and intentional boron dilution. A Completion Time of 1 hour is provided to restore the required channel to OPERABLE status.

As an alternate to restoring the required channel to OPERABLE status Required Action A.2.2.1 requires valves addressed in LCO 3.1.8, "Unborated Water Source Isolation Valves" to be closed to prevent the flow of unborated water into the RCS. Once it is recognized that the required channel is inoperable, the operators will be aware of the possibility of a boron dilution, and the 1 hour Completion Time is adequate to complete the requirements of LCO 3.1.8.

Required Action A.2.2.2 accompanies Required Action A.2.2.1 to verify the SDM according to SR 3.1.1.1 within 1 hour and once per 12 hours thereafter. This backup action is intended to confirm that no unintended boron dilution has occurred while the required channel was inoperable, and that the required SDM has been maintained. The specified Completion Time takes into consideration sufficient time for the initial determination of SDM and other information available in the control room related to SDM.

Required Action A.1 is modified by a Note which permits plant temperature changes provided the temperature change is accounted for in the calculated SDM. Introduction of temperature changes, including temperature increases when a positive MTC exists, must be evaluated to ensure they do not result in a loss of required SDM.

SURVEILLANCE REQUIREMENTS

The required channel is subject to a CHANNEL CHECK and a CHANNEL CALIBRATION. The Surveillance Requirements of this LCO need not be performed on alternate detectors until connected and required OPERABLE in order to meet this LCO.

SR 3.3.8.1

Performance of the CHANNEL CHECK ensures that 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 two

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit 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.

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

SR 3.3.8.2

SR 3.3.8.2 is the performance of a CHANNEL CALIBRATION. CHANNEL CALIBRATION is a complete check of the instrument loop, except for the source range neutron detectors which are excluded from the CHANNEL CALIBRATION as stated in the Note that modifies the Surveillance. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

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

REFERENCES

1. Unit 1 UFSAR Section 14.1.4 and Unit 2 UFSAR Section 15.4.6.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The design method utilized to meet the DNB design criterion for the Robust Fuel Assemblies is the Revised Thermal Design Procedure (RTDP) with the WRB-2M DNB correlation. The design method utilized to meet the DNB design criterion for the VANTAGE 5H fuel assemblies is the RTDP with the WRB-1 DNB correlation. Uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors in the RTDP methodology. RTDP design limit DNBR values are determined in order to meet the DNB design criterion based on the DNB uncertainty factors.

The RTDP design limit DNBR values are 1.22 for the typical and thimble cells for the Robust Fuel Assemblies, and 1.23 and 1.22 for the typical and thimble cells, respectively, for the VANTAGE 5H fuel assemblies.

Additional DNBR margin is maintained by performing the safety analyses to DNBR limits that are higher than the design limit DNBR values. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow, instrumentation biases, etc.), and to provide DNBR margin for design and operating flexibility.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. The parameters used in these analyses are treated in a conservative way from a DNBR standpoint in the STDP methodology. The parameter uncertainties are applied directly to the safety analyses input values to give the lowest minimum DNBR. The design DNBR limit for STDP is the 95/95 limit for the appropriate DNB correlation. Additional DNBR margin is maintained in the safety analyses to offset the applicable DNBR penalties.

BASES

BACKGROUND (continued)

The 95/95 DNBR correlation limit is 1.14 for the WRB-2M DNB correlation, and 1.17 for the WRB-1 and WRB-2 DNB correlations. The WRB -1, WRB-2, or W-3 DNB correlations are used where the WRB-2M DNB correlation is not applicable. The W-3 DNB correlation is used where the WRB-1 and WRB-2 DNB correlations are not applicable. The WRB-2M, WRB-1, and WRB-2 DNB correlations were developed based on mixing vane data, and therefore are only applicable in the heated rod spans above the first mixing vane grid. The W-3 DNB correlation, which does not take credit for mixing vane grids, is used to calculate the DNBR values in the heated region below the first mixing vane grid. The W-3 DNB correlation is applied in the analysis of accident conditions where the system pressure is below the range of the primary correlation. The W-3 DNBR correlation limit is 1.45 for system pressures in the range of 500 to 1,000 psia. The W-3 DNBR correlation limit is 1.30 for system pressures greater than 1,000 psia.

The WRB-1 and WRB-2M DNB correlations are associated with transients that could impact the reactor core safety limits. These correlations, along with the WRB-2 and W-3 DNB correlations, are used in support of the licensing basis transient analyses.

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the applicable DNBR criteria. The applicable DNBR criteria provide the acceptance limits for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the applicable DNBR criteria. Key transients analyzed for DNB concerns include loss of coolant flow events and dropped or stuck rod events. A key assumption in the analyses of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The pressurizer pressure limit and RCS average temperature limit specified in the COLR correspond to the analytical limits used in the safety analyses, with allowance for measurement uncertainty. The analytical values include measurement uncertainties for the non-RTDP events. The measurement uncertainties are included in the DNBR limit for the RTDP events.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO specifies limits on the monitored process variables - pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, based on maximum analyzed steam generator tube plugging, is retained in the TS LCO. The RCS flow value retained in the LCO is an analytical limit used in the safety analysis. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

In order to verify the analytical RCS flow value specified in the LCO, the measured RCS total flow rate is adjusted for measurement error based on performing a precision heat balance and using the result to calibrate the RCS flow rate indicators.

The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location and have been adjusted for instrument error.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit is provided in SL 2.1.1, "Reactor Core SLs." The conditions which define the DNBR limit are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

BASES

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not 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 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

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

SR 3.4.1.2

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

SR 3.4.1.3

The Surveillance for RCS total flow rate is performed using the installed flow instrumentation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

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

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 7 days after ≥ 95% RTP. This exception is appropriate since the heat balance requires the plant to be close to 100% RTP to obtain the required RCS flow accuracies. The Surveillance shall be performed within 7 days after reaching 95% RTP.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1), and UFSAR Chapter 15 (Unit 2).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

APPLICABLE SAFETY ANALYSES

The RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs). However, the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs. DBAs that assume the HZP temperature as an initial condition include the rod cluster control assembly (RCCA) withdrawal from subcritical, RCCA ejection, and main steam line break. Each of these events assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

BASES

APPLICABLE SAFETY ANALYSES (continued)

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 547°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.9, "PHYSICS TESTS Exceptions - MODE 2," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, 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 2 with $K_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with $K_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 541°F. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached.

REFERENCES

1. UFSAR Chapter 14 (Unit 1), and UFSAR Chapter 15 (Unit 2).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 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 leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature (Ref. 1).

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

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section XI, Appendix G (Ref. 3).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

BASES

BACKGROUND (continued)

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

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

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. The methodology for determining the P/T limits is identified in Reference 1. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

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

BASES

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

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

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

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature,

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

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

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," LCO 3.4.2, "RCS Minimum Temperature for Criticality," and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

BASES

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

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

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

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.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 A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

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

BASES

ACTIONS (continued)

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 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.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

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

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required when RCS pressure and temperature conditions are undergoing planned changes. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. Pressure and Temperature Limits Report (PTLR).
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G.
4. ASTM E 185-82, July 1982.
5. 10 CFR 50, Appendix H.
6. Regulatory Guide 1.99, Revision 2, May 1988.
7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission,

b. Improving the neutron economy by acting as a reflector,

c. Carrying the soluble neutron poison, boric acid,

d. Providing a second barrier against fission product release to the environment, and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through three loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

All of the safety analyses performed at full rated thermal power assume that all three RCS loops are in operation as an initial condition (Ref. 1). Some safety analyses have been performed at zero power conditions assuming only two RCS loops are in operation to conservatively bound lower MODES of operation. The events which assume that two RCPs are in operation are the uncontrolled RCCA (Bank) withdrawal from

BASES

APPLICABLE SAFETY ANALYSES (continued)

subcritical, and the zero power rod ejection events. While all safety analyses performed at full rated thermal power assume that all RCS loops are in operation, certain events examine the effects resulting from the loss of an RCS loop. These events include the partial loss of forced RCS flow and the RCP rotor seizure/shaft break. It is demonstrated that all applicable acceptance criteria are met for each of these events. The remaining safety analyses assume operation of all three RCS loops during the event, up to the time of reactor trip, to ensure that all applicable acceptance criteria are met. The events analyzed beyond the time of reactor trip were examined assuming that a loss of offsite power occurs, which results in the coastdown of the RCPs.

Plant operation with all RCS loops in operation in MODES 1 and 2 ensures adequate heat transfer between the reactor coolant and the fuel cladding.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, three pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

In MODES 3, 4, and 5, the decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops - MODE 3,"
LCO 3.4.6, "RCS Loops - MODE 4,"
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled,"
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled,"

BASES

APPLICABILITY (continued)

LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. The reactor shutdown reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR Chapter 14 (Unit 1) and UFSAR Chapter 15 (Unit 2).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops - MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through three RCS loops, connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, one additional RCS loop is required to be OPERABLE to ensure redundant capability for decay heat removal.

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized and the Rod Control System is capable of withdrawing rods, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with the Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops - MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with the Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

When the Rod Control System is not capable of rod withdrawal, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure that a redundant RCS loop is available for decay heat removal.

The Note permits all RCPs to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve. Pump coastdown is modeled in a number of accident analyses, including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again. Another test performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow.

The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

BASES

LCO (continued)

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with the Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.1.10, "RCS Boron Limitations < 500°F,"
LCO 3.4.4, "RCS Loops - MODES 1 and 2,"
LCO 3.4.6, "RCS Loops - MODE 4,"
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled,"
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled,"
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

BASES

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration for Required Action A.1 is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If one required RCS loop is not in operation, and the Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to place the Rod Control System in a condition incapable of rod withdrawal (e.g., de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets or by opening all of the individual rod lift coil disconnect switches). When the Rod Control System is capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must be rendered incapable of rod withdrawal. The Completion Times of 1 hour, to restore the required RCS loop to operation or defeat the Rod Control System is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

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

If two required RCS loops are inoperable or no RCS loop is in operation, except during conditions permitted by the Note in the LCO section, the Rod Control System must be placed in a condition incapable of rod withdrawal (e.g., all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets or by opening all of the individual rod lift coil disconnect switches). All operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM

BASES

ACTIONS (continued)

of LCO 3.1.1 must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets or by opening all of the individual rod lift coil disconnect switches removes the possibility of an inadvertent rod withdrawal. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 28% (Unit 1) or ≥ 15.5% (Unit 2) for required RCS loops. If the SG secondary side narrow range water level is not within the required limit, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.3

Verification that each required RCP is OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to each required RCP not in operation. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through three RCS loops connected in parallel to the reactor vessel, each loop containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is required for decay heat removal. The RCS and RHR loops provide this circulation.

RCS Loops - MODE 4 satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs or RHR pumps to be removed from operation for $\leq$ 1 hour per 8 hour period. The purpose of the Note is to permit pump swapping or tests such as those designed to validate various accident analyses values or confirm equipment operability. The 1 hour time period is adequate to perform pump swaps and most tests that may be necessary in MODE 4, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

BASES

LCO (continued)

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by the test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each non-isolated SG be < 50°F above each of the non-isolated RCS cold leg temperatures before the start of the first RCP with any non-isolated RCS cold leg temperature ≤ the enable temperature specified in the PTLR. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2,"
LCO 3.4.5, "RCS Loops - MODE 3,"
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled,"

BASES

APPLICABILITY (continued)

LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled,"
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If one required loop is inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two loops for heat removal.

A.2

If restoration is not accomplished and an RHR loop is OPERABLE, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 rather than MODE 4. The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

This Required Action is modified by a Note which indicates that the unit must be placed in MODE 5 only if a RHR loop is OPERABLE. With no RHR loop OPERABLE, the unit is in a condition with only limited cooldown capabilities. Therefore, the actions are to be concentrated on the restoration of a RHR loop, rather than a cooldown of extended duration.

B.1 and B.2

If two required loops are inoperable or a required loop is not in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable

BASES

ACTIONS (continued)

margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification that the required RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 28% (Unit 1) or ≥ 15.5% (Unit 2). If the SG secondary side narrow range water level is less than the required limit, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.3

Verification that each required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required pump not in operation. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation (Ref. 1) are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining at least one unisolated SG with a secondary side water level of $\geq$ 28% for Unit 1 or $\geq$ 15.5% for Unit 2 to provide an alternate method for decay heat removal via natural circulation (Ref.1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is required for decay heat removal. The RHR loops provide this circulation.

RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or one unisolated SG with a narrow range secondary side water level ≥ 28% for Unit 1 or ≥ 15.5% for Unit 2. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is one unisolated SG with a narrow range secondary side water level ≥ 28% for Unit 1 or ≥ 15.5% for Unit 2. Should the operating RHR loop fail, the SG could be used to remove the decay heat via natural circulation. Implicit in the provision of this LCO that allows the reliance on a SG for natural circulation are the requirements for an adequate secondary side makeup water supply to maintain the SG level, an adequate steam relief capability to remove decay heat, and for the capability to control RCS pressure to assure the RCS remains pressurized and subcooled during natural circulation. These additional requirements for natural circulation are consistent with the generic recommendations of Reference 1 and the more detailed BVPS Unit 1 and Unit 2 specific recommendations of Reference 2.

Note 1 permits all RHR pumps to be removed from operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit pump swapping or tests such as those designed to validate various accident analyses values or confirm equipment operability. The 1 hour time period is adequate to perform pump swaps and most tests that may be necessary in MODE 5, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by the test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation, and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed when

BASES

LCO (continued)

the testing results in the required RHR loop being rendered inoperable. The remaining OPERABLE RHR loop is adequate to provide the required cooling during the time allowed by Note 2.

Note 3 requires that the secondary side water temperature of each non-isolated SG be < 50°F above each of the non-isolated RCS cold leg temperatures before the start of the first reactor coolant pump (RCP) with a non-isolated RCS cold leg temperature ≤ the enable temperature specified in the PTLR. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops. By permitting the removal of the RHR loops from operation this Note also eliminates the LCO requirement for an RCS loop to provide cooling via natural circulation.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. A SG can perform as a heat sink via natural circulation when it has an adequate water level and is OPERABLE.

APPLICABILITY

In MODE 5 with at least one RCS loop unisolated and filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least one unisolated SG is required to be ≥ 28% for Unit 1 or ≥ 15.5% for Unit 2.

Operation in other MODES is covered by:

LCO 3.4.4,	"RCS Loops - MODES 1 and 2;"
LCO 3.4.5,	"RCS Loops - MODE 3;"
LCO 3.4.6,	"RCS Loops - MODE 4;"
LCO 3.4.8,	"RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.4,	"Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.5,	"Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

BASES

ACTIONS

A.1, A.2, B.1 and B.2

If one RHR loop is OPERABLE and either the required SG has a secondary side water level that is not within the required limit, or one required RHR loop is inoperable, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water level. Either Required Action will restore redundant heat removal loops. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

C.1 and C.2

If a required RHR loop is not in operation, except during conditions permitted by Notes 1 and 4, or if no required loop is OPERABLE, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.2

Verifying that at least one unisolated SG is OPERABLE by ensuring the secondary side narrow range water level is ≥ 28% for Unit 1 or ≥ 15.5% for Unit 2 ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that each required RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required RHR pump not in operation. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. If secondary side water level is ≥ 28% for Unit 1 or ≥ 15.5% for Unit 2 in at least one unisolated SG, this Surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

2. Westinghouse Letter # FENOC-04-228, "Beaver Valley Units 1 and 2 Mode 5, Loops Filled Natural Circulation Cooling Assessment," dated January 31, 2005.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled or isolated, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled or isolated. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled or isolated, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two loops be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is required for decay heat removal. The RHR loops provide this circulation. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet single failure considerations.

Note 1 permits all RHR pumps to be removed from operation for ≤ 15 minutes when switching from one loop to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained > 10°F below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure SDM of LCO 3.1.1 is maintained or draining operations when RHR forced flow is stopped.

BASES

LCO (continued)

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed when the testing results in the required RHR loop being rendered inoperable. The remaining OPERABLE RHR loop is adequate to provide the required cooling during the time allowed by Note 2.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled or isolated, this LCO requires core heat removal and coolant circulation by the RHR System.

Operation in other MODES is covered by:

LCO 3.4.4,	"RCS Loops - MODES 1 and 2,"
LCO 3.4.5,	"RCS Loops - MODE 3,"
LCO 3.4.6,	"RCS Loops - MODE 4,"
LCO 3.4.7,	"RCS Loops - MODE 5, Loops Filled,"
LCO 3.9.4,	"Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.5,	"Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RHR loop is inoperable, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two loops for heat removal.

B.1 and B.2

If no required loop is OPERABLE or the required loop is not in operation, except during conditions permitted by Note 1, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure

BASES

ACTIONS (continued)

continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.2

Verification that each required pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required pump not in operation. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and their controls and emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

BASES

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the UFSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure. Although the safety analyses do not take credit for pressurizer heater operation, the pressurizer heaters are modeled in any transient where pressurizer heater operation could lead to more limiting results (e.g., pressurizer filling events).

The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water volume ≤ 1235 cubic feet, which is equivalent to 92%, ensures that a steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two sets of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW, capable of being powered from the emergency power supply. There are four groups of backup pressurizer heaters powered from emergency busses. Two groups of backup heaters are supplied from each train of emergency power. The LCO requirement for a set of heaters per emergency bus may be met by using any combination of heaters in the two groups powered from the same emergency bus that total ≥ 150 kW of heater capacity. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The amount needed to maintain pressure is dependent on the heat losses.

BASES

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is available or in service, and therefore, the LCO is not applicable.

ACTIONS

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

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level - High Trip.

If the pressurizer water level is not within the limit, action must be taken to bring the plant to a MODE in which the LCO does not apply. To achieve this status, within 6 hours the unit must be brought to MODE 3 with all rods fully inserted and incapable of withdrawal. Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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.

B.1

If one required set of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power would be unlikely in this period. Pressure control will continue to be maintained during this time using the remaining OPERABLE heaters.

BASES

ACTIONS (continued)

C.1 and C.2

If one set of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, 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 6 hours and to MODE 4 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at the required kW capacity. The Surveillance verifies that a total heater capacity of at least 150 kW is available from each emergency bus. Each required set of heaters may be comprised of any combination of heaters in the two groups powered from the same emergency bus. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance or by energizing the heaters and measuring current. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR Chapter 14 (Unit 1), and UFSAR Chapter 15 (Unit 2).

2. NUREG-0737, November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The Unit 1 pressurizer safety valves are totally enclosed, pilot-actuated, self-actuated valves. The Unit 2 pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The rated relief capacity for each valve at both units is 345,000 lbm/hr. The capacity of the pressurizer safety valves is based on the valve geometry. The pressurizer safety valve capacity is used in the analysis of the complete loss of steam flow to the turbine event, to demonstrate that the capacity is sufficient to maintain RCS pressure below 110% of the design pressure. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with one or more RCS cold leg temperatures ≤ the enable temperature specified in the PTLR, and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Overpressure Protection System (OPPS)."

The upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The 1% ASME tolerance requirement is met by assuring the as left lift setting is within 1% of 2485 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

BASES

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the UFSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal at power,

b. Loss of reactor coolant flow,

c. Loss of external electrical load,

d. Loss of normal feedwater,

e. Loss of all AC power to station auxiliaries, and

f. Locked rotor.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation is required in events a, c, d, e, and f (above) to limit the pressure increase. The analysis for some of these events also model the PORVs, because modeling the PORVs leads to more limiting analysis results. Therefore, pressurizer safety valve actuation may not be required in the analysis of these events. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2485 psig), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The safety valves are OPERABLE if the lift settings are found within ± 3% for Unit 1 and +1.6%/-3% for Unit 2. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Reference 1) for lifting pressures above 1000 psig. The 1% ASME tolerance requirement is met by assuring the as left lift setting is within 1% of 2485 psig. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

BASES

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the OPPS enable temperature, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when any RCS cold leg temperature is ≤ the enable temperature specified in the PTLR or in MODE 5 because overpressure protection is provided by the OPPS. Overpressure protection is not required in MODE 6 with the reactor vessel head off.

The Applicability is modified by a Note that allows the lift settings of the safety valves to be verified and set in place when the plant is hot if this method of setting the valves is to be used. Alternate methods of verifying the lift settings (i.e., sending the valves to a test facility) may be used as well, in which case the Note may be ignored. The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this timeframe.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperatures ≤ the enable temperature specified in the PTLR within 24 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

BASES

ACTIONS (continued)

systems. With any RCS cold leg temperatures at or below the enable temperature specified in the PTLR, overpressure protection is provided by the OPPS. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. The lift setting shall correspond to ambient conditions of the valve at nominal temperature and pressure. Nominal temperature and pressure includes MODE 3 operating conditions as provided in the Applicability Note allowing 54 hours for testing and examination of the valves in MODE 3. No additional requirements are specified.

The pressurizer safety valve setpoints are ± 3% of 2485 psig for Unit 1 and +1.6%/-3% of 2485 psig for Unit 2 for OPERABILITY; however, the valves are reset to ± 1% of 2485 psig during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. UFSAR Chapter 14 (Unit 1), and UFSAR Chapter 15 (Unit 2).
3. WCAP-7769, October 1971 (Unit 1) and WCAP-7769, Rev. 1, June 1972 (Unit 2).
4. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

Unit 1 has three air-operated DC powered PORVs. Each PORV is provided with a separate nitrogen backup supply in addition to the normal air supply. Two of the three PORVs are powered from separate trains of DC power. The associated block valves are powered from 480 VAC 1E power supplies. Two of the three block valves are powered from separate trains of AC Power.

Unit 2 has three solenoid-operated DC powered PORVs. Two of the three PORVs are powered from separate trains of DC power. The associated block valves are powered from 480 VAC 1E power supplies. Two of the three block valves are powered from separate trains of AC power such that each PORV and associated block valve are powered from the same train (Ref. 1).

Each PORV has a relief capacity of 210,000 lbm/hr at 2500 psia for Unit 1, and 232,000 lbm/hr at 2350 psia for Unit 2. The functional design of the PORVs is based on maintaining pressure below the Pressurizer

BASES

BACKGROUND (continued)

Pressure - High reactor trip setpoint following a step reduction of 50% of full load with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection. See LCO 3.4.12, "Overpressure Protection System (OPPS)."

APPLICABLE SAFETY ANALYSES

Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are also modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria are critical (Ref. 2). By assuming PORV actuation, the primary pressure remains below the high pressurizer pressure trip setpoint; thus, the DNBR calculation is more conservative. As such, this actuation is not required to mitigate these events, and PORV automatic operation is, therefore, not an assumed safety function.

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

By maintaining at least two PORVs and their associated block valves OPERABLE, two flow paths are provided for RCS pressure control. An OPERABLE block valve may be either open and energized with the capability to be closed, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE when closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function remains available with manual action.

BASES

LCO (continued)

An OPERABLE PORV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria, exists when conditions dictate closure of the block valve to limit leakage.

Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODES 4, 5, and 6 with the reactor vessel head in place when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV requirements in these MODES.

ACTIONS

A Note has been added to clarify that all pressurizer PORVs and block valves are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

BASES

ACTIONS (continued)

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

If one or two PORVs is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. With only one PORV inoperable and not capable of being manually cycled and Required Actions B.1 and B.2 met, operation may continue until the next refueling outage (MODE 6) when the inoperable PORV can be repaired. Continued operation is acceptable because the two remaining PORVs are OPERABLE and provide two flow paths for RCS pressure control.

In addition to the isolation requirements described above, Required Action B.3 requires that one PORV be restored to OPERABLE status in 72 hours. The Required Action is modified by a Note that specifies that Required Action B.3 is only applicable if two PORVs are inoperable. With two of the three PORVs inoperable, one PORV must be restored to OPERABLE status or capable of being manually cycled in order to assure redundant PORV flow paths are available. The Completion Time of 72 hours to restore the required PORV to OPERABLE status or capable of being manually cycled is reasonable because one PORV remains OPERABLE during this time. If the required PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

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

If one PORV block valve is inoperable, either the block valve must be closed or the associated PORV placed in manual control in one hour. If the block valve is closed, it is accomplishing the prime functional requirement (to isolate the associated PORV to prevent an inadvertent RCS depressurization). In this case, operation may continue until the next refueling outage (MODE 6) when the inoperable block valve can be repaired. Continued operation is acceptable because the two remaining block valves and PORVs are OPERABLE and provide two flow paths for RCS pressure control.

BASES

ACTIONS (continued)

If the inoperable block valve can not be closed, it is incapable of performing the prime functional requirement of isolating an inoperable PORV to prevent an inadvertent RCS depressurization. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because two PORVs remain OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORV may not be capable of mitigating an event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 72 hours, the PORV may be restored to automatic operation. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

The Required Actions C.1, C.2.1, and C.2.2 are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then 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 6 hours and to MODE 4 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. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

BASES

ACTIONS (continued)

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

If three PORVs are inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then 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 6 hours and to MODE 4 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. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

F.1, F.2, and F.3

If more than one block valve is inoperable, Required Action F.1 requires that the associated PORVs be placed in manual control within one hour. Placing the PORVs in manual control precludes automatic opening for an overpressure event and avoids the potential for a stuck open PORV at a time that the block valve(s) are inoperable.

Required Action F.2 requires one block valve to be restored to OPERABLE status within 2 hours. The Required Action is modified by a Note that specifies Required Action F.2 is only applicable if three block valves are inoperable. With three block valves inoperable, no fully OPERABLE PORV flow path exists and Action must be taken to restore at least one block valve to OPERABLE status in two hours. The Completion Time of 2 hours is reasonable, based on the small potential for challenges to the system during this time and provide the operator some time to correct the situation.

Required Action F.3 requires that one block valve be restored to OPERABLE status within 72 hours. The Required Action is modified by a Note that specifies that Required Action F.3 is applicable if two block valves are inoperable. With two of the three block valves inoperable, one block valve must be restored to OPERABLE status in order to assure redundant PORV flow paths are available. The Completion Time of 72 hours to restore the required block valve to OPERABLE status is reasonable because one other block valve remains OPERABLE during this time.

BASES

ACTIONS (continued)

The Required Actions F.1, F.2, and F.3 are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunctions(s)).

G.1 and G.2

If the Required Actions of Condition F are not met, then 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 6 hours and to MODE 4 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. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The Note modifies this SR by stating that it is not required to be performed with the block valve closed in accordance with the Required Actions of this LCO. Opening the block valve in this condition increases the risk of an unisolable leak from the RCS since the PORV is already inoperable.

SR 3.4.11.2.1 and SR 3.4.11.2.2

These Unit 1 and 2 surveillances require a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. In addition, the Unit 1 Surveillance (SR 3.4.11.2.1) requires that each PORV be cycled using both the normal air supply and the backup nitrogen supply. Cycling the Unit 1 PORVs using both the normal and backup supply systems actuates the solenoid control valves and check valves to ensure that both

BASES

SURVEILLANCE REQUIREMENTS (continued)

the normal and backup supplies are fully functional. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The surveillances are modified by Notes that identify the Unit for which each Surveillance is applicable.

REFERENCES

1. Regulatory Guide 1.32, February 1977.

2. UFSAR Chapter 14 (Unit 1), and UFSAR Chapter 15 (Unit 2).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Overpressure Protection System (OPPS)

BASES

BACKGROUND

The OPPS controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the MODES when low temperature overpressure protection is required.

The reactor vessel material is less resistant to pressure stress at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all but one charging pump incapable of injection into the RCS and isolating the accumulators. In addition, the Unit 1 ECCS automatic high head safety injection (HHSI) flow path must be isolated. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

With coolant input capability limited to one charging pump, the ability to provide additional core coolant is restricted. Due to the lower pressures in the MODES when low temperature overpressure protection is required and the lower core decay heat levels, the makeup system can provide

BASES

BACKGROUND (continued)

adequate flow via the makeup control valve. If conditions require the use of more than one charging pump for makeup in the event of loss of inventory, then additional pumps can be made available through manual actions.

The OPPS for pressure relief consists of two PORVs with reduced lift settings, or a depressurized RCS and an RCS vent of sufficient size. Two RCS relief valves are required for redundancy. One RCS relief valve has adequate relieving capability to keep from overpressurization for the required coolant input capability.

PORV Requirements

As designed for the OPPS, each PORV is signaled to open if the RCS pressure approaches a limit determined by the OPPS actuation logic. The OPPS actuation logic monitors both RCS temperature and RCS pressure (Unit 2) and RCS pressure (Unit 1) and determines when a condition not acceptable in the PTLR limits is approached. For Unit 2, the wide range RCS temperature indications are auctioneered to select the lowest temperature signal.

In Unit 2, the lowest RCS temperature signal is processed through a function generator that calculates a pressure limit for that temperature. The calculated pressure limit is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The PTLR presents the PORV setpoints for OPPS. In Unit 1, each PORV has the same setpoint. In Unit 2, the setpoints are staggered so only one valve opens during a low temperature overpressure transient. Having the setpoints of both valves within the limits in the PTLR ensures that the Reference 1 limits will not be exceeded in any analyzed event.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

BASES

BACKGROUND (continued)

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere or pressurizer relief tank will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting low temperature overpressure mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it must be the required size. The RCS vent requirement may be satisfied by removing a pressurizer safety valve, or similarly establishing a vent by opening an RCS vent valve of the required size. The vent must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, and in MODE 4 with all RCS cold leg temperatures > the OPPS enable temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. Analyses (Ref. 3) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. When any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR, overpressure prevention is provided by two OPERABLE RCS PORVs or a depressurized and vented RCS with a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the OPPS must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the OPPS requirements. Any change to the RCS must be evaluated against the Reference 3 analyses to determine the impact of the change on the low temperature overpressure protection acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients. The OPPS design basis mass and heat input transients are discussed below.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Mass Input Type Transients

a. Inadvertent safety injection with one charging pump injecting into the RCS via the automatic SI header for Unit 2 or

b. One charging pump injecting into the RCS via the normal charging header with letdown flow isolated for Unit 1.

Heat Input Type Transients

Reactor coolant pump (RCP) startup with temperature asymmetry between the RCS and steam generators.

The following are required during the MODES when low temperature overpressure protection is required to ensure that mass and heat input transients do not occur, which either of the low temperature overpressure protection means cannot provide sufficient relief capacity:

a. Rendering all but one charging pump incapable of injection,

b. Deactivating the accumulator discharge isolation valves in their closed positions,

c. Deactivating the Unit 1 ECCS automatic HHSI isolation valves in their closed positions (to isolate the SI flow path) and

d. Disallowing the start of an RCP if the secondary temperature is more than the limit specified in LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

The Reference 3 analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below the P/T limits when only one charging pump is capable of injecting into the RCS. Thus, the LCO allows only one charging pump capable of injecting into the RCS during the MODES when low temperature overpressure protection is required. The LCO also requires the accumulators isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The isolated accumulators must have their discharge valves closed with the valve power removed. In addition to the isolation of the accumulators, the Unit 1 ECCS automatic HHSI flow path must be isolated with power removed from the isolation valves. The isolation of the Unit 1 automatic HHSI flow path is necessary to prevent an inadvertent SI actuation from potentially overpressurizing the RCS. The SI flow path was not

BASES

APPLICABLE SAFETY ANALYSES (continued)

considered in the Unit 1 OPPS setpoint analysis. The isolation of the Unit 2 SI flow path is not required as the Unit 2 OPPS setpoint analysis considers an inadvertent SI actuation and demonstrates that the Unit 2 OPPS has sufficient capacity to prevent an overpressurization event.

Fracture mechanics and the OPPS setpoint analyses established the temperature of OPPS Applicability, which is the OPPS enable temperature specified in the PTLR.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The setpoints are verified by analyses that model the performance of the OPPS, for the low temperature overpressure transients of one charging pump injecting into the RCS and the start of an RCP when the steam generator secondary side temperature is less than or equal to 50°F higher than the RCS cold leg temperatures. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensure the Reference 1 P/T limits will be met.

The PORV setpoints in the PTLR will be updated when the revised P/T limits are no longer protected by the low temperature overpressure analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 2.07 square inches for Unit 1 or 3.14 square inches for Unit 2 is capable of mitigating the allowed low temperature overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transient for the OPPS configuration, one charging pump capable of injecting into the RCS, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RCS vent is passive and is not subject to active failure.

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

LCO

This LCO requires that the OPPS is OPERABLE. The OPPS is OPERABLE when the minimum coolant input is limited and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires that a maximum of one charging pump be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and immobilized (when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR). In addition, the Unit 1 ECCS automatic HHSI flow path must be isolated with power removed from the isolation valves to prevent an inadvertent SI from overpressurizing the RCS.

The LCO is modified by three Notes. Note 1 allows two charging pumps to be made capable of injecting for ≤ 1 hour during pump swap operations. One hour provides sufficient time to safely complete the actual transfer and to complete the administrative controls and surveillance requirements associated with the swap. The intent is to minimize the actual time that more than one charging pump is physically capable of injection. Note 2 states that an accumulator may be unisolated when the accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions. Note 3 pertains to the Unit 1 specific requirement for the ECCS automatic HHSI flow path to be isolated. The Note provides an allowance for the isolation valves to be opened for the purposes of flow testing or valve stroke testing. The allowance provided by this Note is acceptable as valve position is administratively controlled during testing activities such that the valves can be closed if necessary.

BASES

LCO (continued)

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs,

A PORV is OPERABLE for OPPS when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits, or

b. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when open with an area of ≥ 2.07 square inches for Unit 1 or ≥ 3.14 square inches for Unit 2.

Each of these methods of overpressure prevention is capable of mitigating the limiting low temperature overpressure transient.

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above the OPPS enable temperature specified in the PTLR. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES.
LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above the OPPS enable temperature specified in the PTLR.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable OPPS. There is an increased risk associated with entering MODE 4 from MODE 5 and MODE 5 from MODE 6 with OPPS inoperable 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

With two or more charging pumps capable of injecting into the RCS, RCS overpressurization is possible.

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

B.1, C.1, and C.2

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. The two options are increasing the RCS temperature to > the OPPS enable temperature specified in the PTLR or depressurizing the accumulators below the OPPS limit in the PTLR.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on the low likelihood that an event requiring the OPPS will occur during the allowed times.

D.1

In MODE 4 when any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR, with one required RCS PORV inoperable, the RCS PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two RCS PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the RCS PORVs is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

BASES

ACTIONS (continued)

E.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 4). Thus, with one of the two RCS PORVs inoperable in MODE 5 or in MODE 6 with the head on, the Completion Time to restore two PORVs to OPERABLE status is 24 hours.

The Completion Time represents a reasonable time to investigate and repair several types of PORV failures without exposure to a lengthy period with only one OPERABLE RCS PORV to protect against overpressure events.

F.1

Action Condition F is only applicable to Unit 1. If the Unit 1 ECCS automatic HHSI flow path is unisolated for reasons other than permitted in LCO Note 3, action must be taken to isolate the flow path and remove power from the valve(s) used to isolate the flow path. One hour is allowed to accomplish this action.

The Completion Time of one hour is a reasonable time to accomplish the required task and considers the low likelihood of an overpressure event occurring in this time.

Condition F is modified by a Note. The Note identifies that Condition F is only applicable to Unit 1.

G.1

The RCS must be depressurized and a vent must be established within 12 hours when:

a. Both required RCS PORVs are inoperable,

b. A Required Action and associated Completion Time of Condition D, E, or F is not met, or

c. The OPPS is inoperable for any reason other than Condition A, B, C, D, E, or F.

The vent must be sized ≥ 2.07 square inches for Unit 1 or ≥ 3.14 square inches for Unit 2 to ensure that the flow capacity is greater than that required for the design basis mass input transient during the MODES when low temperature overpressure protection is required. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

BASES

ACTIONS (continued)

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, a maximum of one charging pump is verified capable of injecting into the RCS and the accumulator discharge isolation valves are verified closed with power removed from the valve operator. A charging pump is rendered incapable of injecting into the RCS through removing the power from the pump by racking the breaker out under administrative control or by tagging the control switch in the pull to lock position. An alternate method of low temperature overpressure protection control may be employed using at least two independent means to prevent a pump from injecting into the RCS such that a single failure or single action will not result in an injection into the RCS. This may be accomplished by such means as isolating the discharge of the pump by a closed valve that is tagged in the closed position.

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

SR 3.4.12.3

The RCS vent of ≥ 2.07 square inches for Unit 1 or ≥ 3.14 square inches for Unit 2 is proven OPERABLE by verifying its open condition.

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

The passive vent path arrangement must only be open to be OPERABLE. This Surveillance is required to be met if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.c.2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.4

The PORV block valve must be verified open to provide the flow path for each required PORV to perform its function when actuated. The valve may be remotely verified open in the main control room. This Surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

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

SR 3.4.12.5

This SR is only applicable to Unit 1. The Unit 1 ECCS automatic HHSI flow path must be verified to be isolated by confirming that the required isolation valve(s) are closed and de-energized. The valve(s) utilized to isolate the flow path must be de-energized to prevent an inadvertent SI signal from unisolating the flow path and injecting into the RCS. As this flow path was not specifically evaluated in the Unit 1 OPPS setpoint analysis, the flow path must be maintained isolated to prevent a possible overpressurization of the RCS by an inadvertent SI actuation.

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

SR 3.4.12.6

Performance of a COT is required within 12 hours after decreasing RCS temperature in any cold leg to ≤ the OPPS enable temperature specified in the PTLR if the COT was not previously performed within the Frequency specified in the Surveillance Frequency Control Program on each required PORV to verify and, as necessary, adjust its lift setpoint. A successful test of any 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements. The

BASES

SURVEILLANCE REQUIREMENTS (continued)

COT will verify the setpoint is within the PTLR allowed maximum limits in the PTLR. PORV actuation could depressurize the RCS and is not required. The COT Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A Note has been added indicating that this SR is not required to be performed until 12 hours after decreasing any RCS cold leg temperature to ≤ the OPPS enable temperature specified in the PTLR. This Note provides an exception that allows the COT to be performed when the PORV lift setpoint can be reduced to the OPPS setting if desired. The COT is also met if the Surveillance has been successfully performed in accordance with the Surveillance Frequency Control Program prior to entering the applicable OPPS MODES.

SR 3.4.12.7

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. UFSAR Section 4.2.3 (Unit 1) and UFSAR Section 5.2.2.11 (Unit 2).
4. Generic Letter 90-06.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

10 CFR 50, Appendix A, GDC 30, as discussed in Reference 1, requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45, as discussed in Reference 2, describes acceptable methods for selecting leakage detection systems.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

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

This LCO deals with protection of the reactor coolant pressure boundary (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 (LOCA).

BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event.

Primary to secondary LEAKAGE is a factor in the dose assessment of accidents or transients that involve secondary steam release to the atmosphere, such as a main steam line break (MSLB), a locked rotor accident (LRA), a Loss of AC Power (LACP), a Control Rod Ejection Accident (CREA) and to a lesser extent, a Steam Generator Tube Rupture (SGTR). The leakage contaminates the secondary fluid. The limit on the primary to secondary LEAKAGE ensures that the dose contribution at the site boundary from tube leakage following such accidents are limited to appropriate fractions of the 10 CFR 50.67 limit of 25 Rem TEDE as allowable by Regulatory Guide 1.183. The limit on the primary to secondary leakage also ensures that the dose contribution from tube leakage in the control room is limited to the 10 CFR 50.67 limit of 5 Rem TEDE. Among all of the analyses that release primary side activity to the environment via tube leakage, the MSLB is of particular concern because the ruptured main steam line provides a pathway to release the primary to secondary leakage directly to the environment without dilution in the secondary fluid.

For Unit 1, the safety analysis for an event resulting in steam discharge to the atmosphere conservatively assumes that primary to secondary LEAKAGE from all steam generators is 450 gallons per day (gpd) (i.e., 150 gpd per steam generator) or increases to 450 gpd as a result of accident induced conditions. Currently, the Unit 1 safety analyses do not specifically assume additional primary to secondary LEAKAGE due to accident induced conditions.

For Unit 2, due to adoption of the voltage based steam generator tube repair criteria per guidance provided by Generic Letter (GL) 95-05 (Reference 3), the safety analysis for an event resulting in steam discharge to the atmosphere conservatively assumes that primary to secondary LEAKAGE from all steam generators is 450 gallons per day (gpd) (i.e., 150 gpd per steam generator) or increases to 450 gpd as a result of accident induced conditions for all accidents other than the MSLB. Currently, the Unit 2 MSLB safety analysis is the only analysis that specifically assumes additional primary to secondary LEAKAGE due to accident induced conditions.

The Unit 2 dose consequences associated with the MSLB addresses an additional 2.1 gpm leakage, which, per GL 95-05, is postulated to occur (via pre-existing tube defects) as a result of the rapid depressurization of the secondary side due to the MLSB, and the consequent high differential pressure across the faulted steam generator. The maximum allowed Unit 2 total accident induced leakage is 2.4 gpm.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. 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. Should pressure boundary LEAKAGE occur through a component which can be isolated from the balance of the Reactor Coolant System, plant operation may continue provided the leaking component is promptly isolated from the Reactor Coolant System since isolation removes the source of potential failure.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

BASES

LCO (continued)

d. Primary to Secondary LEAKAGE through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or primary to secondary LEAKAGE is not within limit, or if unidentified or identified LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the

BASES

ACTIONS (continued)

LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

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. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown and RCP seal injection and return flows) and near operating pressure. The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

BASES

SURVEILLANCE REQUIREMENTS (continued)

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the instrumentation systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

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

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.20, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature (25°C) as described in Reference 5. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. UFSAR Section 4.2.7.1 (Unit 1) and UFSAR Section 5.2.5 (Unit 2).

BASES

REFERENCES (continued)

3. NRC Generic Letter 95-05: Voltage-Based Repair Criteria For Westinghouse Steam Generator Tubes Affected By Outside Diameter Stress Corrosion Cracking.

4. NEI 97-06, "Steam Generator Program Guidelines."

5. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A, as discussed in Reference 1, define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through two series valves is determined by a water inventory balance (SR 3.4.13.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight.

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

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 2) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 3) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

The specific PIVs addressed by this LCO are listed in the Licensing Requirements Manual (LRM).

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

BASES

APPLICABLE SAFETY ANALYSES

Reference 2 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the Emergency Core Cooling System Low Head Injection System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the Low Head Injection System downstream of the PIVs from the RCS. Because the low pressure portion of the system is not designed for RCS pressure, overpressurization failure of the low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

Reference 3 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific PIVs for which this LCO applies are listed in the LRM. RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. Note 4 in SR 3.4.14.1 provides an exception to the 0.5 gpm/inch diameter limit under certain circumstances.

Reference 4 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power. This allowance is consistent with that provided by Note 3 in SR 3.4.14.1.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR mode of operation.

In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1

The flow path must be isolated. Required Action A.1 is modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Motor-operated valves used to meet this isolation requirement shall be placed in the closed position with power supplies de-energized.

B.1 and B.2

If leakage cannot be reduced, or the other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

The list of valves for which this Surveillance is applicable is contained in the LRM. Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating compliance within the valve leakage criteria. In addition, for those valves where the leakage rate can be continuously monitored during plant operation, no other leakage rate testing is required. The leakage rate of valves continously monitored shall be recorded at intervals that satisfy the required Surveillance Frequency.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed for all PIVs listed in the LRM prior to entering MODE 2 after the plant is placed in MODE 5 for refueling. The Frequency, which results in testing the PIVs approximately every 18 months, is within the requirements of 10 CFR 50.55a(f) as contained in the Inservice Testing Program, and is also within the frequency allowed by the American Society of Mechanical Engineers (ASME) Code (Ref. 4), which is based on the need to perform such surveillances under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. However, this does not preclude performance of this Surveillance at power, if necessary to confirm OPERABILITY, when it can be accomplished in a safe manner.

An additional Frequency of "prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months" is applicable to certain PIVs. This additional Frequency is modified by a Note that clarifies that this Frequency is only applicable to PIVs specifically identified in the list of PIVs in the LRM. The additional testing is specified for PIVs identified as "Event V" (potential loss of coolant accident outside containment) type PIVs consistent with References 2 and 3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures not possible in the MODES with lower temperature restrictions.

Entry into MODES 3 and 4 is allowed to establish higher differential pressures if necessary for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2, if leakage testing has not been performed in the previous 9 months. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

Note 3 provides the allowance that the RCS PIV leakage may be verified at a pressure lower than the required RCS pressure range provided the observed leakage rates are adjusted to the function maximum pressure in accordance with ASME OM Code (Ref. 4).

Note 4 provides an exception to the 0.5 gpm/inch diameter leakage limit of the LCO. The Note allows leakage rates $>$ 0.5 gpm/inch diameter but $\leq$ 5.0 gpm total provided the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by $\geq$ 50%.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U. S. Nuclear Regulatory Commission General Design Criteria"

2. WASH-1400 (NUREG-75/014), Appendix V, October 1975.

3. NUREG-0677, May 1980.

4. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50, as discussed in Reference 1, requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45, Revision 0, as discussed in Reference 2, describes acceptable methods for selecting leakage detection systems.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

The non-Emergency Core Cooling System (ECCS) portion of the containment sump used to collect unidentified LEAKAGE is capable of indicating increases above the normal level.

The reactor coolant contains radioactivity that, when released to the containment, may be detected by radiation monitoring instrumentation. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE.

Other indications may be used to detect an increase in unidentified LEAKAGE; however, they are not required to be OPERABLE by this LCO. An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment sump. Humidity level monitoring is considered most useful as an indirect indication to inform the operator to a potential problem. Humidity monitors are not required by this LCO.

BASES

BACKGROUND (continued)

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements is affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

The above-mentioned LEAKAGE detection methods or systems differ in sensitivity and response time. Some of these systems could serve as early warning systems signaling the operators that closer examination of other detection systems is necessary to determine the extent of any corrective action that may be required.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leakage occur detrimental to the safety of the unit and the public.

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

LCO

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of unidentified LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO requires two instruments to be OPERABLE.

BASES

LCO (continued)

The non-ECCS portion of the containment sump is used to collect unidentified LEAKAGE. The monitor on the containment sump detects level or flow rate and is instrumented to detect when there is an increase above the normal value. The identification of an increase in unidentified LEAKAGE will be delayed by the time required for the unidentified LEAKAGE to travel to the containment sump and it may take longer than one hour to detect a 1 gpm increase in unidentified LEAKAGE, depending on the origin and magnitude of the LEAKAGE. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by the gaseous or particulate containment atmosphere radioactivity monitor. Only one of the two detectors is required to be OPERABLE. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE, but have recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate containment atmosphere radioactivity monitors to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous or particulate containment atmosphere radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in unidentified LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 3).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor, in combination with a gaseous or particulate radioactivity monitor, provides an acceptable minimum. The containment sump monitor is comprised of the instruments associated with the non-ECCS portion of the containment sump which monitor narrow range level and sump pump discharge flow. The LCO only requires that the sump level or discharge flow monitor be OPERABLE. The required particulate and gaseous radioactivity monitors are RM-1RM-215A&B (Unit 1) and 2RMR-RQ303A&B (Unit 2).

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

BASES

APPLICABILITY (continued)

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

With the required containment sump monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the containment atmosphere radioactivity monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the required sump monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

B.1.1, B.1.2, and B.2

With both gaseous and particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitors.

BASES

ACTIONS (continued)

The 24 hour interval provides periodic information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1 and C.2

With the required containment sump monitor inoperable, the only means of detecting LEAKAGE is the required containment atmosphere radiation monitor. A Note clarifies that this Condition is applicable when the containment atmosphere gaseous radioactivity monitor is the only OPERABLE monitor. The containment atmosphere gaseous radioactivity monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. In addition, this configuration does not provide the required diverse means of leakage detection. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the containment atmosphere must be obtained to provide alternate periodic information. The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

D.1 and D.2

If a Required Action of Condition A, B, or C cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.15.3 and SR 3.4.15.4

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria."

2. Regulatory Guide 1.45, Revision 0, “Reactor Coolant Pressure Boundary Leakage Detection Systems,” May 1973.

3. UFSAR Section 4.2.7.1 (Unit 1) and UFSAR Section 5.2.5 (Unit 2).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The total effective dose equivalent (TEDE) that an individual at the site boundary can receive for 2 hours during an accident and the total effective dose equivalent that a resident at the low population zone can receive during the course of an accident are specified in 10 CFR 50.67 (Ref. 1). The limits on specific activity ensure that the doses are held to an appropriate fraction of the 10 CFR 50.67 limits during analyzed transients and accidents. The TS limits also ensure that the total effective dose equivalent to a control room operator is within the dose limits specified by 10 CFR 50.67.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam line break (SLB) or steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the TEDE at the site boundary and in the control room to an appropriate fraction of the 10 CFR 50.67 dose guideline limits. The limits in the LCO are based on BVPS specific radiological consequence analyses.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensure that the resulting TEDE at the site boundary and in the control room will not exceed an appropriate fraction of the 10 CFR 50.67 dose guideline limits following a SLB or SGTR accident. The SLB or SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 150 gallons per day (gpd) in each of the three steam generators. In addition, the Unit 2 SLB analysis assumes additional leakage that is calculated as described in Generic Letter 95-05 (Ref. 3) for facilities that have implemented steam generator alternate repair criteria. The safety analysis also assumes the specific activity of the secondary coolant at its limit of DOSE EQUIVALENT I-131 specified in LCO 3.7.13, "Secondary Specific Activity."

The analysis for the SLB or SGTR accident establishes the acceptance limits for RCS specific activity. References to these analyses are used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analyses are for two cases of reactor coolant specific activity. One case assumes specific activity at 0.35 µCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the I-131 activity appearance rate in the reactor coolant by a factor of 500 (SLB) or 335 (SGTR) immediately after the accident. The second case assumes the initial reactor coolant iodine activity at 21 µCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant is based on the equilibrium concentrations predicted while operating with 1% failed fuel, and proportionately reduced to correspond to the reduced concentrations of DOSE EQUIVALENT I-131.

The safety analyses show the radiological consequences of an SLB or SGTR accident are within the Reference 1 dose guideline limits for the pre-accident iodine spike case, and well within the 10 CFR 50.67 dose guidelines for the concurrent iodine spike case. Operation with iodine specific activity levels greater than the LCO limit is permissible for up to 48 hours, if the activity levels do not exceed the limits shown in Figure 3.4.16-1. The safety analysis has pre-accident iodine spiking levels up to 21 µCi/gm DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a SLB or SGTR accident occurring during the established 48 hour time limit. The occurrence of an SLB or SGTR accident at the permissible levels applicable from 80 to 100% power could increase the site boundary dose levels, but still be within 10 CFR 50.67 dose guideline limits.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to 0.35 µCi/gm DOSE EQUIVALENT I-131, and the gross specific activity in the reactor coolant is limited to the number of µCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the non-iodine coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the TEDE at the site boundary and in the control room during the Design Basis Accident (DBA) will be an appropriate fraction of the allowed TEDE dose. The limit on gross specific activity provides an additional indication of radionuclides (excluding iodines) that corresponds closely to the noble gas activity in the RCS and helps to ensure the effective doses during the DBA will be an appropriate fraction of the allowed dose.

BASES

LCO (continued)

The SLB and SGTR accident analyses (Ref. 2) show that the resultant dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SLB or SGTR, lead to site boundary or control room doses that exceed the 10 CFR 50.67 dose guideline limits.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity are necessary to limit the potential radiological consequences of an SLB or SGTR to within the acceptable site boundary and control room dose values.

For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the secondary side steam pressure is significantly reduced which in turn reduces the probability and severity of a SLB or a SGTR.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the limits of Figure 3.4.16-1 are not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is required, if the limit violation resulted from normal iodine spiking.

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 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.

BASES

ACTIONS (continued)

B.1

With the gross specific activity in excess of the allowed limit, the unit must be placed in a MODE in which the requirement does not apply.

The change within 6 hours to MODE 3 and RCS average temperature < 500°F lowers the secondary side steam pressure which in turn reduces the probability and severity of a SLB or SGTR. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

C.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is in the unacceptable region of Figure 3.4.16-1, the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with T_{avg} at least 500°F. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.2

This Surveillance is required to be performed in MODE 1 only to ensure iodine remains within limit during normal operation and following fast power changes when fuel failure is more apt to occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

SR 3.4.16.3

A radiochemical analysis for $\overline{E}$ determination is required with the plant operating in MODE 1 equilibrium conditions. The $\overline{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\overline{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR has been modified by a Note that indicates sampling is not required to be performed until 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours. This ensures that the radioactive materials are at equilibrium so the analysis for $\overline{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. 10 CFR 50.67.

2. UFSAR Section 14.2.5 and 14.2.4 (Unit 1) and UFSAR Section 15.1.5 and 15.6.3 (Unit 2).

3. NRC Generic Letter 95-05: Voltage-Based Repair Criteria For Westinghouse Steam Generator Tubes Affected By Outside Diameter Stress Corrosion Cracking.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 RCS Loop Isolation Valves

BASES

BACKGROUND

The reactor coolant loops are equipped with loop isolation valves that permit any loop to be isolated from the reactor vessel. One valve is installed on each hot leg and one on each cold leg. The loop isolation valves may be used to perform tasks such as maintenance or inspections on an isolated loop. Power operation with a loop isolated is not permitted.

To ensure that inadvertent closure of a loop isolation valve does not occur, the valves must be open with power to the valve operators removed in MODES 1, 2, 3 and 4. If the valves are closed, a set of administrative controls must be satisfied prior to opening the isolation valves as described in LCO 3.4.18, "RCS Isolated Loop Startup."

APPLICABLE SAFETY ANALYSES

The safety analyses performed for the reactor at power assume that all reactor coolant loops are initially in operation and the loop isolation valves are open. This LCO places controls on the loop isolation valves to ensure that the valves are not inadvertently closed in MODES 1, 2, 3 and 4. The inadvertent closure of a loop isolation valve when the Reactor Coolant Pumps (RCPs) are operating will result in a partial loss of forced reactor coolant flow (Ref. 1). If the reactor is at power at the time of the event, the effect of the partial loss of forced coolant flow is a rapid increase in the coolant temperature which could result in DNB with subsequent fuel damage if the reactor is not tripped by the Low Flow reactor trip. If the reactor is shutdown and an RCS loop is in operation removing decay heat, closure of the loop isolation valve associated with the operating loop could also result in increasing coolant temperature and the possibility of fuel damage.

RCS Loop Isolation Valves satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that the loop isolation valves are open and power to the valve operators is removed. Loop isolation valves may be used for tasks such as performing maintenance or inspections in MODES 5 and 6. The safety analyses assume that the loop isolation valves are open in any RCS loops required to be OPERABLE by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," or LCO 3.4.6, "RCS Loops - MODE 4."

BASES

APPLICABILITY

In MODES 1 through 4, this LCO ensures that the loop isolation valves are open and power to the valve operators is removed. The safety analyses assume that the loop isolation valves are open in any RCS loops required to be OPERABLE.

In MODES 5 and 6, the loop isolation valves may be closed. Controlled startup of an isolated loop is governed by the requirements of LCO 3.4.18, "RCS Isolated Loop Startup."

ACTIONS

The Actions have been provided with a Note to clarify that all RCS loop isolation valves for this LCO are treated as separate entities, each with separate Completion Times, i.e., the Completion Time is on a component basis.

A.1

If power is inadvertently restored to one or more loop isolation valve operators, the potential exists for accidental isolation of a loop. The loop isolation valves have motor operators. Therefore, these valves will maintain their last position when power is removed from the valve operator. With power applied to the valve operators, only the controls and surveillances required by the Technical Specifications prevent the valve from being operated. Although the controls and surveillances required by the Technical Specifications make the occurrence of this event unlikely, the prudent action is to remove power from the loop isolation valve operators. The Completion Time of 30 minutes to remove power from the loop isolation valve operators is sufficient considering the complexity of the task.

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

Should a loop isolation valve be closed in MODES 1 through 4, the affected loop isolation valve(s) must remain closed and the plant placed in MODE 5. Once in MODE 5, the isolated loop may be started in a controlled manner in accordance with LCO 3.4.18, "RCS Isolated Loop Startup." Opening the closed isolation valve in MODES 1 through 4 could result in colder water or water at a lower boron concentration being mixed with the operating RCS loops resulting in positive reactivity insertion. The Completion Time of Condition B allows time for borating the operating loops to a shutdown boration level such that the plant can be brought to MODE 3 within 6 hours and MODE 5 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

The Surveillance is performed to ensure that the RCS loop isolation valves are open, with power removed from the loop isolation valve operators. The primary function of this Surveillance is to ensure that power is removed from the valve operators, since SR 3.4.4.1 of LCO 3.4.4, "RCS Loops - MODES 1 and 2," ensures that the loop isolation valves are open by verifying every 12 hours that all loops are operating and circulating reactor coolant. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR Section 14.1.5 (Unit 1) and UFSAR Section 15.3.1 (Unit 2).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.18 RCS Isolated Loop Startup

BASES

BACKGROUND

The RCS may be operated with loops isolated in MODES 5 and 6 in order to perform tasks such as maintenance or inspections. While operating with a loop isolated, there is potential for inadvertently opening the isolation valves in the isolated loop. In this event, the coolant in the isolated loop would suddenly begin to mix with the coolant in the operating loops. This situation has the potential of causing a positive reactivity addition with a corresponding reduction of SDM if:

a. The boron concentration in the isolated loop is lower than the boron concentration required to meet the SDM of LCO 3.1.1 when in MODE 5 or the boron concentration of LCO 3.9.1 when in MODE 6 (boron dilution incident), and

b. The isolated portion of the RCS loop has not been drained and refilled from the refueling water storage tank (RWST) or RCS.

As discussed in the UFSAR (Ref. 1), the startup of an isolated loop is done in a controlled manner that virtually eliminates any undesirable reactivity addition from cold water or boron dilution because:

a. This LCO and plant operating procedures require that the boron concentration in the isolated loop be maintained ≥ the boron concentration required to maintain SDM, thus eliminating the potential for introducing coolant from the isolated loop that could dilute the boron concentration in the operating loops, below the concentration necessary to maintain the required SDM.

b. In addition, this LCO and plant operating procedures require that the isolated portion of the RCS loop be drained and refilled with water from the RWST or RCS. These requirements ensure the loop is filled with water that has a boron concentration and a temperature that are within the limits assumed in the applicable SDM calculation. In addition, the refilling of the loop ensures that the borated water in the loop is well mixed prior to unisolating the loop.

BASES

APPLICABLE SAFETY ANALYSES

During startup of an isolated loop, the controls required by this LCO prevent opening the loop isolation valves until the isolated loop is drained and refilled from the RWST or the RCS. In addition, the boron concentration of the isolated loop is verified to be within the limit for the required SDM. This ensures that any undesirable reactivity effect from the isolated loop does not occur.

The safety analyses assume a minimum SDM as an initial condition for Design Basis Accidents. Violation of this LCO could result in the SDM being reduced in the operating loops to less than that assumed in the safety analyses.

The boron concentration of an isolated loop may affect SDM. Therefore, RCS isolated loop startup satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Loop isolation valves may be used for performing tasks such as maintenance or inspections when the plant is in MODE 5 or 6. This LCO ensures that the loop isolation valves remain closed until the affected loop is drained and refilled from the RWST or RCS and the boron concentration of the isolated loops is verified to be within acceptable limit to maintain the required SDM.

APPLICABILITY

In MODES 5 and 6, when an RCS loop has been isolated for > 4 hours or drained this LCO becomes applicable to recover the affected loop. In MODES 5 and 6, the required SDM is large enough to permit operation with isolated loops. Controlled startup of isolated loops is possible without significant risk of inadvertent criticality. This LCO is applicable under these conditions.

In MODES 1, 2, 3, and 4 LCO 3.4.17, "RCS Loop Isolation Valves," requires that all loop isolation valves be open with power removed from the valve operator. In MODES 5 and 6 if a loop is isolated for $\leq$ 4 hours and not drained the condition of the isolated loop has not changed significantly. Therefore, under these conditions, LCO 3.4.18 is not applicable.

ACTIONS

A.1

Required Action A.1 assumes that the prerequisites of the LCO are not met and a loop isolation valve has been inadvertently opened. Therefore, the Actions require immediate closure of isolation valves to preclude a boron dilution event or a cold water event.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1

This Surveillance verifies the isolated portion of the affected RCS loop is drained and refilled with water from the RWST or RCS. This verification provides assurance that the loop is filled with water that has a boron concentration and a temperature that are within the limits assumed in the applicable SDM calculation. The Frequency of prior to opening the isolated loop hot or cold leg isolation valve provides additional assurance an isolated loop is returned to service in accordance with the provisions of LCO 3.4.18.

SR 3.4.18.2

To ensure that the boron concentration of the isolated loop is greater than or equal to the boron concentration required to meet the SDM of LCO 3.1.1 or boron concentration of LCO 3.9.1, this Surveillance is performed 2 hours prior to opening either the hot or cold leg isolation valve. Performing the Surveillance 2 hours prior to opening either the hot or cold leg isolation valve provides reasonable assurance the boron concentration will stay within acceptable limits until the loop is unisolated. This Frequency has been shown to be acceptable through operating experience.

SR 3.4.18.3

This Surveillance verifies the isolated loop hot or cold leg isolation valve is opened within 4 hours following completion of the isolated loop refill. This verification confirms that the loop being returned to service has been recently refilled in accordance with SR 3.4.18.1. The Frequency of within 4 hours after completion of the refill provides assurance that there is no significant change in boron concentration or temperature of the water in the loop since refill and that the contents of the loop remain well mixed when the loop is unisolated.

REFERENCES

1. UFSAR Section 14.1.6 (Unit 1) and Section 15.4.4 (Unit 2).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.19 RCS Loops – Test Exceptions

BASES

BACKGROUND

The primary purpose of this test exception is to provide an exception to LCO 3.4.4, "RCS Loops - MODES 1 and 2," to permit reactor criticality under no flow conditions during certain PHYSICS TESTS (natural circulation demonstration, station blackout, and loss of offsite power) to be performed while at low THERMAL POWER levels. Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the power plant as specified in GDC 1, "Quality Standards and Records" (Ref. 2).

The key objectives of a test program are to provide assurance that the facility has been adequately designed to validate the analytical models used in the design and analysis, to verify the assumptions used to predict plant response, to provide assurance that installation of equipment at the unit has been accomplished in accordance with the design, and to verify that the operating and emergency procedures are adequate. Testing may be performed prior to initial criticality, during startup, and following low power operations.

The tests may include verifying the ability to establish and maintain natural circulation following a plant trip between 10% and 20% RTP, performing natural circulation cooldown on emergency power, and during the cooldown, showing that adequate boron mixture occurs and that pressure can be controlled using auxiliary spray and pressurizer heaters powered from the emergency power sources.

APPLICABLE SAFETY ANALYSES

The tests described above require operating the plant without forced convection flow and as such are not bounded by any safety analyses. However, operating experience has demonstrated this exception to be safe under the present applicability.

As described in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. Test Exception 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.

BASES

LCO

This LCO provides an exemption to the requirements of LCO 3.4.4.

The LCO is provided to allow for the performance of PHYSICS TESTS in MODE 2 (after a refueling), where the core cooling requirements are significantly different than after the core has been operating. Without the LCO, plant operations would be held bound to the normal operating LCOs for reactor coolant loops and circulation (MODES 1 and 2), and the appropriate tests could not be performed.

In MODE 2, where core power level is considerably lower and the associated PHYSICS TESTS must be performed, operation is allowed under no flow conditions provided THERMAL POWER is ≤ P-7 and the reactor trip setpoints of the OPERABLE power level channels are set in accordance with the nominal trip setpoints specified in the Licensing Requirements Manual (LRM). This ensures, if some problem caused the plant to enter MODE 1 and start increasing plant power, the Reactor Trip System (RTS) would automatically shut it down before power became too high, and thereby prevent violation of fuel design limits.

The exemption is allowed even though there are no bounding safety analyses. However, these tests are performed under close supervision during the test program and provide valuable information on the plant's capability to cool down without offsite power available to the reactor coolant pumps.

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS without any forced convection flow. This testing is performed to establish that heat input from nuclear heat does not exceed the natural circulation heat removal capabilities. Therefore, no safety or fuel design limits will be violated as a result of the associated tests.

ACTIONS

A.1

When THERMAL POWER is ≥ the P-7 interlock setpoint (as specified for P-10 and P-13 in the LRM), the only acceptable action is to ensure the reactor trip breakers (RTBs) are opened immediately in accordance with Required Action A.1 to prevent operation of the fuel beyond its design limits. Opening the RTBs will shut down the reactor and prevent operation of the fuel outside of its design limits.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.19.1

Verification that the power level is < the P-7 interlock setpoint (as specified for P-10 and P-13 in the LRM) will ensure that the fuel design criteria are not violated during the performance of the PHYSICS TESTS. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.19.2

The specified power range and intermediate range neutron flux channels and the P-10 and P-13 interlock setpoints must be verified to be OPERABLE and adjusted to the proper value. The Low Power Reactor Trips Block, P-7 interlock, is actuated from either the Power Range Neutron Flux, P-10, or the Turbine First Stage Pressure, P-13 interlock. The P-7 interlock is a logic Function with train, not channel identity. A COT is performed prior to initiation of the PHYSICS TESTS. The purpose of this Surveillance is to verify the required COT has been performed on the specified channels consistent with the requirements of LCO 3.3.1, "Reactor Trip System." If the Surveillance Requirements of LCO 3.3.1 are current, no additional testing is required by this Surveillance. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS. A successful test of any 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 COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements. The SR 3.3.1.7 and SR 3.3.1.11 Frequencies are sufficient for the specified channels to ensure the instrumentation is OPERABLE before initiating PHYSICS TESTS.

SR 3.4.19.3

The Low Power Reactor Trips Block, P-7 interlock, must be verified to be OPERABLE in MODE 1 by LCO 3.3.1, "Reactor Trip System Instrumentation." The P-7 interlock is actuated from either the Power Range Neutron Flux, P-10, or the Turbine First Stage Pressure, P-13 interlock. The P-7 interlock is a logic Function. An ACTUATION LOGIC TEST is performed to verify OPERABILITY of the P-7 interlock prior to initiation of startup and PHYSICS TESTS. The purpose of this Surveillance is to verify the required ACTUATION LOGIC TEST has been

BASES

SURVEILLANCE REQUIREMENTS (continued)

performed on the P-7 interlock consistent with the requirements of LCO 3.3.1, "Reactor Trip System." If the Surveillance Requirements of LCO 3.3.1 are current, no additional testing is required by this Surveillance. This will ensure that the RTS is properly functioning to provide the required degree of core protection during the performance of the PHYSICS TESTS. The SR 3.3.1.5 Frequency is sufficient for the P-7 interlock to ensure the instrumentation is OPERABLE before initiating PHYSICS TESTS.

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.

2. 10 CFR 50, Appendix A, GDC 1, 1988.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.20 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops – MODES 1 and 2," LCO 3.4.5, "RCS Loops – MODE 3," LCO 3.4.6, "RCS Loops – MODE 4," and LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Depending upon materials and design, steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.5, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.5, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.5. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes that following reactor trip the contaminated secondary fluid is released to the atmosphere via safety valves. Environmental releases before reactor trip are discharged through the main condenser.

For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. Pre-accident and concurrent iodine spikes are assumed in accordance with applicable regulatory guidance. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of 10 CFR 50.67 (Ref. 2) as supplemented by Regulatory Guide 1.183 (Ref. 3) and within GDC-19 (Ref. 4) values.

Unit 1:

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is conservatively assumed to include the total primary to secondary LEAKAGE from all SGs of 450 gpd (i.e., 150 gpd per steam generator) or is assumed to increase to 450 gpd as a result of accident induced conditions. Currently, the Unit 1 safety analyses do not specifically assume additional primary to secondary LEAKAGE due to accident induced conditions.

Unit 2:

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In these analyses, the steam discharge to the atmosphere is conservatively assumed to include the total primary to secondary LEAKAGE from all SGs of 450 gpd (i.e., 150 gpd per steam generator) or is assumed to increase to 450 gpd as a result of accident induced conditions for all accidents other than the Unit 2 main steam line break (MSLB). Currently, the Unit 2 MSLB safety analysis is the only analysis that specifically assumes additional primary to secondary LEAKAGE due to accident induced conditions.

For the Unit 2 main steam line break (MSLB) analysis, an increased leakage assumption is applied. In support of voltage based repair criteria pursuant to Generic Letter 95-05 (Ref. 5) analyses were performed to

BASES

APPLICABLE SAFETY ANALYSES (continued)

determine the maximum MSLB induced primary to secondary leak rate that could occur without offsite doses exceeding the limits of 10 CFR 50.67 (Ref. 2) as supplemented by Regulatory Guide 1.183 (Ref. 3) and without control room doses exceeding GDC-19 (Ref. 4). An additional 2.1 gpm leakage is assumed in the Unit 2 MSLB analysis resulting from accident conditions. Therefore, in the MSLB analysis, the steam discharge to the atmosphere includes primary to secondary LEAKAGE equivalent to the operational leakage limit of 150 gpd per SG and an additional 2.1 gpm which results in a total assumed accident induced leakage of 2.4 gpm.

The combined projected leak rate from all sources (i.e., voltage based repair criteria, application of F*, freespan crack, leaking plug, leakage past sleeves, etc.) for each SG must be less than the maximum allowable steam line break leak rate limit in any one steam generator (i.e., 2.2 gpm) in order to maintain a total assumed accident induced leakage of ≤ 2.4 gpm as explained above. Maintaining the total assumed accident induced leakage to ≤ 2.4 gpm limits the resulting dose to within the requirements of 10 CFR 50.67 (Ref. 2) as supplemented by Regulatory Guide 1.183 (Ref. 3) and within GDC-19 (Ref. 4) values during a postulated steam line break event.

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

A Note modifies the LCO to indicate that any reference to the repair of SG tubes is only applicable to Unit 2 at this time. The Unit 1 "Steam Generator Program" (in Specification 5.5.5) has no provision for SG tube repair.

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging or repair criteria be plugged or repaired in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging or repair criteria is repaired or removed from service by plugging. If a tube was determined to satisfy the plugging or repair criteria but was not plugged or repaired, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall and any repairs made to it, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.5, "Steam

BASES

LCO (continued)

Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 6) and Draft Regulatory Guide 1.121 (Ref. 7).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions as described in the Applicable Safety Analyses section of this Bases. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

BASES

LCO (continued)

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

A Note modifies Condition A and Required Action A.2 to indicate that any reference to the repair of SG tubes is only applicable to Unit 2 at this time. The Unit 1 "Steam Generator Program" (in Specification 5.5.5) has no provision for SG tube repair.

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging or repair criteria but were not plugged or repaired in accordance with the Steam Generator Program as required by SR 3.4.20.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging or repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube

BASES

ACTIONS (continued)

that should have been plugged or repaired has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged or repaired prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.20.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Steam Generator Program in conjunction with the degradation assessment determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging or repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program and the degradation assessment also specify the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.20.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 8). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.5 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections. If crack indications are found in any SG tube, the maximum inspection interval for all affected and potentially affected SGs is restricted by Specification 5.5.5 until subsequent inspections support extending the inspection interval.

SR 3.4.20.2

A Note modifies SR 3.4.20.2 to indicate that any reference to the repair of SG tubes is only applicable to Unit 2 at this time. The Unit 1 "Steam Generator Program" (in Specification 5.5.5) has no provision for SG tube repair.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging or repair criteria is repaired or removed from service by plugging. The tube plugging or repair criteria delineated in Specification 5.5.5 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging or repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Steam generator tube repairs are only performed using approved repair methods as described in the Steam Generator Program (Specification 5.5.5).

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging or repair criteria are plugged or repaired prior to subjecting the SG tubes to significant primary to secondary pressure differential.

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50.67, Accident Source Term.
3. Regulatory Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors."
4. 10 CFR 50 Appendix A, GDC 19.
5. NRC Generic Letter 95-05, "Voltage-Based Repair Criteria For Westinghouse Steam Generator Tubes Affected By Outside Diameter Stress Corrosion Cracking."
6. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
7. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
8. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a large break loss of coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for a small break LOCA.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a large break LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of safety injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series.

The accumulator size, water volume, and nitrogen cover pressure are selected so that two of the three accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that two accumulators are adequate for this function is consistent with the large break LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of a large break LOCA.

BASES

APPLICABLE SAFETY ANALYSES

The accumulators are assumed to be OPERABLE in both the large and small break LOCA analyses at full power and hot zero power (HZP) steam line break (SLB) analysis (Ref. 1). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a large break LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg large break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break in the cold leg for both Units 1 and 2. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

No credit is taken for ECCS pump flow in the analysis until full flow is available. If offsite power is not available, the analysis accounts for the diesels starting and the pumps being loaded and delivering full flow. During this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and charging pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the charging pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

a. Maximum fuel element cladding temperature is $\leq$ 2200°F,

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

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

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a large break LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The nominal water volume assumed in the analyses is within the range of accumulator volumes specified in Surveillance Requirement 3.5.1.2. The contained water volume is not the same as the usable volume of the accumulators, since the accumulators are not completely emptied after discharge. For large breaks, an increase in water volume can be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. Therefore, the large break LOCA analyses use a range of accumulator volumes. The Unit 1 ASTRUM large break LOCA analysis statistically calculates the accumulator water volume over the range of accumulator volumes specified in Surveillance Requirement 3.5.1.2. For Unit 2, the large break LOCA analysis assumes values of 6898 gallons and 8019 gallons for accumulator volume. The large break LOCA analyses also credit the line water volume from the accumulator to the check valve.

The minimum boron concentration is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

The small break LOCA analysis is performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that a higher nitrogen cover pressure results in a computed peak clad

BASES

APPLICABLE SAFETY ANALYSES (continued)

temperature benefit. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity. The accumulators also discharge following a SLB; however, their impact is minor with respect to meeting the design basis DNB limit.

The specified Technical Specification values for the usable accumulator volume, boron concentration, and minimum nitrogen pressure are analysis values. Also, the values specified for nitrogen pressure and volume do not account for instrument uncertainty.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Ref 3).

The accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Three accumulators are required to ensure that 100% of the contents of two of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than two accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 2000 psig, and the limits established in the SRs for usable volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

BASES

APPLICABILITY (continued)

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators discharge following a large main steam line break at hot zero power (HZP); however, their impact is minor with respect to meeting the design basis departure from nucleate boiling (DNB) limit. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of two accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hour Completion Time to open the valve, remove power from the valve operator control circuit, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions and is justified in Reference 4.

C.1 and C.2

If the accumulator cannot be returned 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

BASES

ACTIONS (continued)

brought to MODE 3 within 6 hours and RCS pressure reduced to ≤ 1000 psig 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 more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator isolation valve should be verified to be fully open. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change once power is removed from the control circuit, a closed valve could result in not meeting accident analyses assumptions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.2 and SR 3.5.1.3

The usable borated water volume and nitrogen cover pressure are verified for each accumulator. The required accumulator water volumes and minimum nitrogen pressure value are analysis values. The values specified for accumulator water volume do not include the line water volume from the accumulator to the check valve and do not account for instrumentation uncertainty. Similarly, the values specified for the nitrogen cover pressure also do not account for instrumentation uncertainty. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

The value specified for boron concentration is an analysis value. The boron concentration should be verified to be within required limits for each accumulator since the static design of the accumulators limits the ways in which the concentration can be changed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Sampling the affected accumulator within 6 hours after a ≥ 1% accumulator volume increase will identify whether inleakage has caused a reduction in boron concentration to below the required limit. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage tank (RWST), because the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 5).

SR 3.5.1.5

Verification that power is removed from each accumulator isolation valve operator control circuit when the RCS pressure is > 2000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only one accumulator would be available for injection given a single failure coincident with a LOCA. Power is removed from the accumulator motor operated isolation valves control circuits by removing the plug in the lock out jack from the associated control circuits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR allows power to be supplied to the motor operated isolation valves control circuits when RCS pressure is ≤ 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to remove control power during plant startups or shutdowns.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1) and UFSAR, Chapter 15 (Unit 2).
2. 10 CFR 50.46.
3. UFSAR, Chapter 14 (Unit 1) and UFSAR, Chapter 6 (Unit 2).
4. WCAP-15049-A, Risk-Informed Evaluation of an Extension to Accumulator Completion Times, Rev. 1, April 1999.
5. NUREG-1366, February 1990.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS - Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system,

b. Rod ejection accident,

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater, and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to power.

There are three phases of ECCS operation: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sumps have enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the containment sump for cold leg recirculation. After approximately 6.5 hours (Unit 1) or 6 hours (Unit 2), the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

The ECCS consists of two redundant, 100% capacity trains. Each ECCS train consists of two subsystems: the High Head Safety Injection (HHSI) subsystem and a Low Head Safety Injection (LHSI) subsystem. The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS flow paths consist of piping, valves, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The Chemical and Volume Control System charging pumps in both units are also utilized as HHSI pumps during a safety injection. For Unit 1, the major component of the HHSI

BASES

BACKGROUND (continued)

subsystem is a charging pump (HHSI pump) and the major component of the LHSI subsystem is the LHSI pump. For Unit 2, the major component of the HHSI subsystem is a charging pump (HHSI pump). The Unit 2 LHSI subsystem is comprised of a LHSI pump used for the ECCS injection mode of operation and a recirculation spray pump (2RSS-P21C or 2RSS-P21D) and associated recirculation spray heat exchanger used for the ECCS recirculation mode of operation. The HHSI and LHSI subsystems of each ECCS train are interconnected such that each ECCS train may utilize HHSI or LHSI subsystem components from the other ECCS train. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core.

For Unit 1, during the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. Water from the supply header enters the LHSI pumps through parallel, normally open, motor operated valves. Water to the HHSI pumps is supplied via parallel motor operated valves to ensure that at least one valve opens on receipt of a safety injection actuation signal. The supply header then branches to the three HHSI pumps. The discharge from the HHSI pumps divides into three supply lines, each of which feeds the injection line to one RCS cold leg. One HHSI pump is dedicated to each train of ECCS. The third pump is a "swing" pump that can be substituted for either dedicated HHSI pump in an ECCS train. The discharge from the LHSI pumps combines into one line and then divides to feed an injection line to each of the RCS cold legs. Throttle valves in the HHSI injection lines are set to balance the flow to the RCS. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

For Unit 2, during the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. Water from the supply header enters the LHSI pumps through parallel, normally open, motor operated valves. Water to the HHSI pumps is supplied via parallel motor operated valves to ensure that at least one valve opens on receipt of a safety injection actuation signal. The supply header then branches to the three HHSI pumps. The discharge from the HHSI pumps is provided to two separate discharge lines, each of which then divides into three supply lines. Each of these supply lines feeds the injection line to one RCS cold leg. One HHSI pump is dedicated to each train of ECCS. The third pump is a "swing" pump that can be substituted for either dedicated HHSI pump in an ECCS train. The discharge from the LHSI pumps is provided to two separate lines that combine into one line and then divide to feed an injection line to each of the RCS cold legs. Throttle valves in the HHSI lines are set to balance the flow to the RCS and limit pump runout. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

BASES

BACKGROUND (continued)

For LOCAs that are too small to depressurize the RCS below the shutoff head of the LHSI pumps, the HHSI pumps supply water until the RCS pressure decreases below the LHSI pump shutoff head. During this period, the steam generators provide part of the core cooling function.

For Unit 1, during the recirculation phase of LOCA recovery, LHSI pump suction is transferred to the containment sump. The LHSI pumps can also supply the HHSI pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation alternates injection between the hot and cold legs.

For Unit 2, during the recirculation phase of LOCA recovery, LHSI pumps are stopped and the LHSI function is provided by two of the four recirculation spray pumps (2RSS-P21C and 2RSS-P21D). The discharge of the two recirculation spray pumps is automatically aligned to the LHSI piping and recirculation spray pump suction is provided from the containment sump. The two recirculation spray pumps can also supply the HHSI pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation alternates injection between the hot and cold legs.

The HHSI subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

The ECCS subsystems are actuated upon receipt of an SI signal. If offsite power is available, the safeguard loads start immediately. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The HHSI pumps "A" and "B" are capable of being automatically started and are powered from separate ESF buses. HHSI pump "C" can be powered from either of the ESF buses that HHSI pump "A" or "B" is powered from. An interlock prevents HHSI pump "C" from being powered from both ESF buses simultaneously. In the event of a safety injection actuation signal coincident with a loss of offsite power, interlocks prevent operation of two HHSI pumps on the same bus to prevent overloading the EDGs.

BASES

BACKGROUND (continued)

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 as discussed in Reference 1.

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

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

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

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

d. Core is maintained in a coolable geometry, and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Ref. 3). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The HHSI pumps are credited in a small break LOCA event. The small break LOCA is an important consideration in determining the performance requirements of the HHSI pumps. The SGTR and MSLB events also credit the HHSI pumps. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with a loss of offsite power or offsite power available and a single failure disabling one ECCS train and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Ref. 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the HHSI pumps will deliver sufficient water during a small LOCA to maintain RCS inventory. For smaller LOCAs, the HHSI pump delivers sufficient fluid to maintain RCS inventory. For a small break LOCA, the steam generators continue to serve as a heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

For Unit 1, in MODES 1, 2, and 3, an ECCS train consists of an HHSI subsystem and an LHSI subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon a safety injection actuation signal and transferring suction to the containment sump during the recirculation phase of operation.

For Unit 2, in MODES 1, 2, and 3, an ECCS train consists of an HHSI subsystem and an LHSI subsystem. The Unit 2 LHSI subsystem includes a recirculation spray pump capable of supplying the SI flow path during the recirculation phase of operation. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and transferring suction to the containment sump during the recirculation phase of operation.

BASES

LCO (continued)

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the three cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow simultaneously to both the RCS hot or cold legs for Unit 1. The flow path from the containment sump is cycled alternatively between the RCS cold legs or hot legs for Unit 2.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

The LCO is modified by three Notes. Note 1 provides an exception allowing the LHSI flow paths to be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room.

As indicated in Note 2, operation in MODE 3 with one required charging pump made incapable of injecting in order to facilitate entry into or exit from the Applicability of LCO 3.4.12, "Overpressure Protection System (OPPS)," is necessary when OPPS enable temperature is at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that one required charging pump be rendered incapable of injecting at and below the OPPS enable temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to make a required charging pump incapable of injecting prior to entering the OPPS Applicability, and provide time to restore the inoperable pump to OPERABLE status on exiting the OPPS Applicability.

Note 3 is only applicable to Unit 1. As indicated in Note 3, operation in MODE 3 with the Unit 1 ECCS automatic high head safety injection (HHSI) flow path isolated in order to facilitate entry into or exit from the Applicability of LCO 3.4.12, "Overpressure Protection System (OPPS)," is necessary when the OPPS enable temperature is at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that the Unit 1 ECCS automatic HHSI flow path be isolated when any RCS cold leg temperature is ≤ the enable temperature specified in the PTLR. When this temperature is near the MODE 3 boundary temperature, Note 3 provides time to isolate the ECCS automatic HHSI flow path prior to entering the OPPS Applicability, and to restore the flow path on exiting the OPPS Applicability.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With one or more trains inoperable and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one active component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS (e.g., an inoperable HHSI pump in one train and an inoperable LHSI pump in the other train). This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable trains cannot be returned 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 MODE 3 within 6 hours and MODE 4 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.

C.1

Condition A is applicable with one or more trains inoperable. The allowed Completion Time is based on the assumption that at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available. With less than 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the facility is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves by removing the plug from the lockout circuit of valve operator control circuit ensures they cannot change position as a result of active failure or be inadvertently misaligned. These valves are of the type that can disable the function of both ECCS trains and invalidate the accident analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.2

Verification that the HHSI pump minimum flow valve (MOV-1CH-373 for Unit 1 and 2CHS*MOV373 for Unit 2) is open with power removed ensures that spurious or inadvertent closure of this valve is prevented. Closure of this valve could cause overheating of each of the HHSI pumps (potentially rendering both ECCS trains inoperable). Securing this valve in position by removal of power ensures that it cannot change position as a result of an active failure or be inadvertently misaligned. The verification that the valve is in the open position may be accomplished by verifying flow through the minimum flow path using control room indication, by local verification of correct valve stem position, or by local flow verification using temporary instruments. The verification that the

BASES

SURVEILLANCE REQUIREMENTS (continued)

valve motor operator is de-energized may be accomplished by verifying the absence of valve position indicator lights. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.3

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 actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance 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.

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the ECCS Flow Analysis excluding the Unit 2 recirculation spray pumps 2RSS-P21C and 2RSS-P21D. The specific acceptance criteria of the "required developed head" for each ECCS pump may be found in the Inservice Testing (IST) Program and the ECCS Flow Analysis, as applicable. The term "required developed head" refers to the pump performance at a given flow point that is assumed in the ECCS Flow Analysis. This is possible since the analysis assumes the pump delivers different flows at different times during accident mitigation. These multiple points are represented by a curve. The values at various flow points are defined by the Minimum Operating Point (MOP) curve in the IST. The verification that the pump's developed head at the flow test point is greater than or equal to the required developed head is performed by using the MOP curve.

BASES

SURVEILLANCE REQUIREMENTS (continued)

For the Unit 2 recirculation spray pumps 2RSS-P21C and 2RSS-P21D, the term "required developed head" refers to the value that is assumed in the Containment Integrity Safety Analysis for the recirculation spray pump's developed head at a specific flow point. This value for the required developed head at a flow point is defined as the MOP in the IST Program. The verification that the pump's developed head at the flow test point is greater than or equal to the required developed head is performed by using a MOP curve. The MOP curve is contained in the IST Program and was developed using the required developed head at a specific flow point as a reference point. From the reference point, a curve was drawn which is a constant percentage below the current pump performance curve. Based on the MOP curve, a verification is performed to ensure that the pump's developed head at the flow test point is greater than or equal to the required developed head. SRs are specified in the IST Program of the ASME Code. The ASME Code provides the activities and frequencies necessary to satisfy the requirements.

SR 3.5.2.5 and SR 3.5.2.6

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump, except 2RSS-P21C and 2RSS-P21D, starts on receipt of an actual or simulated SI signal. The Unit 2 recirculation spray pumps 2RSS-P21C and 2RSS-P21D start on a receipt of an actual or simulated coincidence Containment Pressure - High High signal and RWST Level Low signal or a coincidence RWST Level Extreme Low and SI signal.

For the Automatic Switchover to the Containment Sump function of the ECCS, these Surveillances include a verification of the associated required slave relay operation. The Automatic Switchover to the Containment Sump, Function 7 in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," does not include a requirement to perform a SLAVE RELAY TEST due to equipment safety concerns if such a test was performed at power. Therefore, verification of the required slave relay OPERABILITY for the Automatic Switchover to the Containment Sump ESFAS function is included in these ECCS Surveillances. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls.

The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

Periodic inspections of the accessible regions of the containment sump suction inlet strainers ensure that they are unrestricted, free of structural distress or abnormal corrosion, and stay in proper operating condition. Accessible regions of the sump strainers are those regions that can be visually examined without disassembling the strainer assembly or the grating and cover plates over the strainer assembly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Appendix 1A, "1971 AEC General Design Criteria Conformance, " (Unit 1) and UFSAR, Section 3.1, "Conformance with U.S. Nuclear Regulatory Commission General Design Criteria, " (Unit 2).

2. 10 CFR 50.46.

3. UFSAR, Section 14.3 (Unit 1) and UFSAR, Section 15.6.5 (Unit 2).

4. UFSAR, Section 14.3.4 (Unit 1) and UFSAR, Section 6.2.1 (Unit 2).

5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS - Operating," is applicable to these Bases, with the following modifications.

For Unit 1, in MODE 4, the required ECCS train consists of two subsystems: High Head Safety Injection (HHSI) and the Low Head Safety Injection (LHSI). For Unit 2, in MODE 4, the required ECCS train consists of two subsystems: HHSI and the LHSI (which includes a LHSI pump and recirculation spray pump 2RSS-P21C or 2RSS-P21D and associated heat exchanger).

The ECCS flow paths consist of piping, valves, and pumps such that water from the refueling water storage tank (RWST) can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that certain automatic safety injection (SI) actuation is not available. In this MODE, sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

Only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODE 4, one of the two independent (and redundant) ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA.

For Unit 1, in MODE 4, an ECCS train consists of an HHSI subsystem and an LHSI subsystem. The train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon being manually realigned and transferring suction to the containment sump during the recirculation phase of operation. For Unit 2, in MODE 4, an ECCS train consists of an HHSI subsystem and a LHSI subsystem that includes a LHSI pump used in the injection mode of

BASES

LCO (continued)

operation and recirculation spray pumps 2RSS-P21C or 2RSS-P21D (as applicable) and associated heat exchangers capable of supplying the SI flow path during the recirculation mode of operation. The train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon being manually realigned and transferring suction to the containment sump during the recirculation mode of operation.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the three cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to deliver its flow simultaneously to both the RCS hot or cold legs for Unit 1. The flow path from the containment sump is cycled alternately between the RCS cold legs or hot legs for Unit 2.

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350°F, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS high head subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head 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.

BASES

ACTIONS (continued)

A.1

With no ECCS train OPERABLE, the plant is not prepared to respond to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one ECCS train to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS train is not required.

B.1

When the Required Actions of Condition A cannot be completed within the required Completion Time, the plant must be placed in MODE 5. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

The applicable references from Bases 3.5.2 apply.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling cavity during refueling, and to the ECCS and the Quench Spray System during accident conditions.

The RWST supplies water to the ECCS pumps through a common supply header. Water from the supply header enters the Low Head Safety Injection (LHSI) pumps through parallel, normally open, motor operated valves. Water to the charging pumps (i.e., the High Head Safety Injection (HHSI) pumps) is supplied via parallel motor operated valves to ensure that at least one valve opens on receipt of a safety injection actuation signal. The supply header then branches to the three HHSI pumps. The RWST supplies water to the quench spray pumps via separate redundant lines. A motor operated isolation valve is provided to isolate the RWST from the ECCS once the system has been transferred to the recirculation mode. The recirculation mode is entered when pump suction is transferred to the containment sump following receipt of the RWST Low level signal (Unit 1) or the RWST Extreme level signal (Unit 2). Use of a single RWST to supply both trains of the ECCS and Quench Spray System is acceptable since the RWST is a passive component used for a short period of time following an accident, and passive failures are not required to be assumed to occur during the time the RWST is needed following Design Basis Events.

The switchover from normal operation to the injection phase of ECCS operation requires changing HHSI pump suction from the CVCS volume control tank (VCT) to the RWST through the use of isolation valves. Each set of isolation valves is interlocked so that the VCT isolation valves will begin to close once the RWST isolation valves are fully open. Since the VCT is under pressure, the preferred pump suction will be from the VCT until the tank is isolated. This will result in a delay in obtaining the RWST borated water. The effects of this delay are discussed in the Applicable Safety Analyses section of these Bases.

During normal operation, the LHSI pumps of the ECCS and the quench spray pumps are aligned to take suction from the RWST.

The ECCS pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

BASES

BACKGROUND (continued)

When the suction for the ECCS pumps is transferred to the containment sump, the recirculation flow paths are isolated from the RWST to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the atmosphere.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase and the Quench Spray System,

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and Recirculation Spray System pumps at the time of transfer to the recirculation mode of cooling, and

c. The reactor remains subcritical following a loss of coolant accident (LOCA).

Insufficient water volume in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Quench Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS - Operating," B 3.5.3, "ECCS - Shutdown," and B 3.6.6, "Quench Spray System." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for certain non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The usable volume limit is set by the LOCA and containment analyses. For the RWST, the usable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The minimum boron concentration limit is an important assumption in ensuring the required shutdown capability. The maximum boron concentration is an explicit assumption in "Spurious Operation of the Safety Injection System at Power" (Unit 1) and "Inadvertent Operation of the ECCS During Power Operation" (Unit 2), however, the results are very insensitive to boron concentration. The maximum temperature ensures that the amount of cooling provided from the RWST during the heatup phase of a feedline break is consistent with safety analysis assumptions; the minimum temperature is an assumption in both the MSLB analysis and the "Spurious Operation of the Safety Injection System at Power" (Unit 1) and "Inadvertent Operation of the ECCS During Power Operation" (Unit 2).

The RWST temperature impacts the large and small break LOCA peak cladding temperature (PCT) calculations, and the LOCA and MSLB containment peak pressure calculations.

LOCA PCT Calculations:

The large break LOCA analysis assumes that the quench spray temperature is equal to the RWST lower limit of 45°F. The lower RWST temperature results in a reduced containment backpressure, which increases steam binding, reducing the flooding rate and results in an increased PCT. The small break LOCA analysis assumes an RWST temperature of 65°F.

Containment Integrity Calculations:

Both the LOCA and MSLB containment integrity analyses credit the quench spray to reduce the containment pressure following the accident. The LOCA and MSLB containment analyses assume that the quench spray temperature is greater than or equal to the upper RWST temperature limit of 65°F. A higher RWST temperature results in a reduced cooling and condensation spray capability, and therefore higher calculated containment pressures.

The MSLB analysis has considered a delay associated with the interlock between the VCT and RWST isolation valves, and the results show that the departure from nucleate boiling design basis is met. The assumed response times are provided in the Licensing Requirements Manual.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For a large break LOCA analysis, the minimum usable water volume of 317,000 gallons (Unit 1) and 368,000 gallons (Unit 2) and the lower boron concentration limit of 2400 ppm are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case with respect to assuring subcriticality, since the safety analysis assumes that all control rods are out of the core.

The containment iodine removal offsite dose radiological analysis and containment sump pH analysis and HHSI pump net positive suction head calculation assume a minimum useable volume of 430,500 gallons (Unit 1) and 859,248 gallons (Unit 2), and therefore establish the required limit.

The upper limit on boron concentration of 2600 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a large break LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

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

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the containment sump to support ECCS and Recirculation Spray System pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the usable water volume, boron concentration, and temperature limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Quench Spray System OPERABILITY requirements. Since both the ECCS and the Quench Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

BASES

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Quench Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection and spray.

B.1

With the RWST inoperable for reasons other than Condition A (e.g., water volume), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Quench Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned 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 6 hours and to MODE 5 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified to be within the limits assumed in the accident analyses band. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperatures are within the operating limits of the RWST. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

SR 3.5.4.2

The RWST water volume should be verified to be above the required usable level in order to ensure that a sufficient initial supply is available for injection and the Quench Spray System and to support continued ECCS and Recirculation Spray System pump operation on recirculation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.4.3

The boron concentration of the RWST should be verified to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that boron precipitation in the core will not occur and that the resulting sump pH will be maintained in an acceptable range so the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1) and UFSAR, Chapter 6 and Chapter 15 (Unit 2).

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

The function of the seal injection throttle valves during an accident is similar to the function of the ECCS throttle valves in that each restricts flow from the charging pump header to the Reactor Coolant System (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during SI. The RCP seal injection flow is restricted by the seal injection line flow resistance which is adjusted through positioning of the manual seal injection throttle valves. The RCP seal injection flow is determined by measuring the charging pump discharge pressure, and the RCP seal injection flow rate.

The seal injection flow control valve fails open to ensure that, in the event of either loss of air or loss of control signal to the valve, when the charging pumps are supplying charging flow, seal injection to the RCP seals is maintained. Positioning of the seal injection flow control valve may vary during normal plant operating conditions, resulting in a proportional change to RCP seal injection flow. The flow provided by seal injection throttle valves will remain fixed when seal injection flow control valve is repositioned provided the throttle valve position(s) are not adjusted.

APPLICABLE SAFETY ANALYSES

ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The minimum flow provided by the ECCS pumps is modeled in the LOCA analysis. The charging pumps are also credited in the small break LOCA analysis. The small break LOCA analysis establishes the flow and discharge head at the design point for the charging pumps. The steam generator tube rupture, feedline break and main steam line break event analyses also credit the charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

This LCO ensures that seal injection flow will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the

BASES

APPLICABLE SAFETY ANALYSES (continued)

charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory.

Seal injection flow satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The intent of the LCO limit on seal injection flow is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient charging pump injection flow is directed to the RCS via the injection points.

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a pressure and flow must be known. The flow line resistance is determined by assuming that the RCS pressure is at normal operating pressure and that the charging pump discharge pressure is greater than or equal to the value specified in this LCO. The charging pump discharge pressure remains essentially constant through all the applicable MODES of this LCO. A reduction in RCS pressure would result in more flow being diverted to the RCP seal injection line than at normal operating pressure. The valve settings established at the prescribed charging pump discharge pressure result in a conservative valve position should RCS pressure decrease. The additional modifier of this LCO, the seal injection flow control valve being full open, is required since the valve is designed to fail open for the accident condition. With the discharge pressure and control valve position as specified by the LCO, a flow limit is established. It is this flow limit that is used in the accident analyses.

The limit on seal injection flow must be met to ensure that the ECCS is OPERABLE. If these conditions are not met, the ECCS flow will not be as assumed in the accident analyses.

APPLICABILITY

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower; however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in these MODES. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

BASES

ACTIONS

A.1

With the seal injection flow outside its limit, the amount of charging flow available to the RCS may be reduced. In this Condition, action must be taken to restore the flow to within its limit with charging pump discharge pressure ≥ 2457 psig and the seal injection control valve full open. The operator has 4 hours from the time the flow is known to be outside the limit to correctly position the manual valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is conservative with respect to the Completion Times of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.

B.1 and B.2

When the Required Actions cannot be completed within the required Completion Time, a controlled shutdown must be initiated. The Completion Time of 6 hours for reaching MODE 3 from MODE 1 is a reasonable time for a controlled shutdown, based on operating experience and normal cooldown rates, and does not challenge plant safety systems or operators. Continuing the shutdown begun in Required Action B.1, an additional 6 hours is a reasonable time, based on operating experience and normal cooldown rates, to reach MODE 4, where this LCO is no longer applicable.

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

Verification that the manual seal injection throttle valves are adjusted to give a flow within the limit ensures that the ECCS injection flows stay within the safety analysis assumptions. The flow shall be verified by confirming seal injection flow ≤ 28 gpm with the RCS at normal operating pressure, the seal injection flow control valve full open, and the charging pump discharge pressure ≥ 2457 psig. The seal injection flow control valve in the flow path between the charging pump discharge and the RCS must be fully open during this Surveillance to correlate with the acceptance criteria. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

As noted, the Surveillance is not required to be performed until 4 hours after the RCS pressure has stabilized within a ± 20 psig range of normal operating pressure. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual valves are set correctly. The exception is limited to 4 hours to ensure that the Surveillance is timely.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1) and UFSAR, Chapter 6 and Chapter 15 (Unit 2).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a design basis loss of coolant accident (LOCA). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat foundation mat, and a dome roof. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The concrete reactor building is required for structural integrity of the containment under Design Basis Accident (DBA) conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1), as modified by approved exemptions.

The isolation devices for the penetrations in the 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 3.6.3, "Containment Isolation Valves,"

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks,"

c. The equipment hatch is closed, and

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

BASES

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting Design Basis Accident (DBA) without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a LOCA, a steam line break, and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. A main steam line break inside containment is not evaluated as the dose consequences are bounded by a main steam line break outside containment. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.1% per day in the safety analysis at P_a = 43.1 psig (for Unit 1) and 44.8 psig (for Unit 2) (Ref. 3).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

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

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq$ 1.0 L_a, except during the first unit startup prior to entering MODE 4 after performing a required Containment Leakage Rate Testing Program leakage test. At this time the other applicable leakage limits specified in the Containment Leakage Rate Testing Program must be met.

Compliance with this LCO will ensure a containment configuration, including equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates for the containment air lock (LCO 3.6.2) are specified in the Containment Leakage Rate Testing Program and are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding the air lock limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, 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 containment during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If 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 6 hours and to MODE 5 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

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in LCO 3.6.2 does not invalidate the acceptability of these overall leakage determinations unless the air lock leakage contribution to overall Type A, B, and C leakage causes that leakage to exceed the following limits. As-left leakage prior to entering MODE 4 during the first unit startup after performing a required Containment Leakage Rate Testing Program leakage test is required to be $< 0.6\ L_a$ for combined Type B and C leakage, and $\leq 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on the overall integrated containment leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies

BASES

SURVEILLANCE REQUIREMENTS (continued)

are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. UFSAR, Chapter 14 (Unit 1), and UFSAR, Chapter 15 (Unit 2).
3. UFSAR, Section 5.2 (Unit 1), and UFSAR, Section 6.2 (Unit 2).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder with a door at each end. The emergency air lock is significantly smaller than the personnel airlock and is not used for routine containment entry and exit. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. The emergency air lock, which is located in the equipment hatch opening, is normally removed from the containment building during a refueling outage. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double o-ring seals and local leakage rate testing capability to ensure pressure integrity. DBA conditions that increase containment pressure will result in increased sealing forces on the personnel air lock inner door and both doors on the emergency air lock. As the outer door on the personnel air lock is the only one of these doors that opens outward from containment, it is periodically tested in a manner where the containment DBA pressure is attempting to overcome the door sealing forces.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment and containment pressurization are a loss of coolant accident (LOCA) and a rod ejection accident (REA) (Ref. 1). A main steam line break inside containment is not evaluated as the dose consequences are bounded by a main steam line break outside containment. In the analysis of a design basis LOCA or REA, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate

BASES

APPLICABLE SAFETY ANALYSES (continued)

of 0.1% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B (Ref. 3), as L_a = 0.1% of containment air weight per day, the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a = 43.1 psig (for Unit 1) and 44.8 psig (for Unit 2) following a design basis LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when 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 containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. However, if the inner door is inoperable it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable

BASES

ACTIONS (continued)

due to the low probability of an event that could pressurize the 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.

A second Note has been added 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.

In the event the air lock leakage results in exceeding the overall containment leakage rate acceptance criteria, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

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

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is 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 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means 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.

BASES

ACTIONS (continued)

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the 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. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls to perform activities not related to the repair of affected air lock components. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the 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 more 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 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 and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

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 initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) 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 containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the 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 established by Technical Specification requirements. The periodic testing requirements verify that the air lock leakage does not

BASES

SURVEILLANCE REQUIREMENTS (continued)

exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the 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. This ensures that air lock leakage is properly accounted for in determining the containment leakage rate is within the acceptance criteria specified in the Containment Leakage Rate Testing Program.

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports 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 opening of the inner and outer doors will not inadvertently occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1), and UFSAR, Chapter 15 (Unit 2).
2. UFSAR, Section 5.2 (Unit 1), and UFSAR, Section 6.2 (Unit 2).
3. 10 CFR 50, Appendix J, Option B.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are typically provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

The list of containment penetrations and the associated isolation devices credited for each penetration is specified in the Licensing Requirements Manual (LRM).

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure-High High signal and isolates the remaining process lines, except systems required for accident mitigation. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

BASES

BACKGROUND (continued)

The Shutdown Purge System operates to supply outside air into the containment for ventilation and heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two 42 inch isolation valves. Because of their large size, the 42 inch purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 42 inch purge valves are maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment and containment pressurization are a loss of coolant accident (LOCA) and a rod ejection accident (REA) (Ref. 1). A main steam line break inside containment is not evaluated as the dose consequences are bounded by a steam line break outside containment. In the analyses for a design basis LOCA or REA, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized. The safety analyses assume that the 42 inch purge valves are closed at event initiation.

The DBA radiological dose analysis, is based on the alternate source term methodology (Ref. 2). Although the analysis assumes the containment is isolated to achieve the design leakage rate, the analysis only specifically models the release from, and isolation of, those valves that provide direct access to the outside atmosphere and which may be open during operation (i.e., vacuum pump suction isolation valves). Due to the timing of fission product releases assumed in the radiological dose analyses (per Reference 2) and the relatively fast operation of the containment isolation valves, the operation of other containment isolation valves, after a DBA, is not specifically modeled. However, the required stroke times for containment isolation valves, required to be closed after a DBA, are specified in the LRM and are conservatively maintained consistent with the guidance of Reference 3. The radiological dose

BASES

APPLICABLE SAFETY ANALYSES (continued)

analysis conservatively assumes a post DBA containment leakage at the design leakage rate (L_a) for the first 24 hours and one half the design leakage rate for the next 29 days after the DBA.

The 42 inch containment purge and exhaust valves have not been evaluated to ensure they can be closed automatically in MODES 1, 2, 3, and 4 to mitigate the effects of a DBA inside containment. Therefore, the 42 inch containment purge and exhaust valves are maintained deactivated in the closed position in MODES 1, 2, 3, and 4 to prevent spurious or inadvertent operation of the valves.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 42-inch purge valves must be maintained deactivated in the closed position. The valves covered by this LCO are listed along with their associated stroke times in the LRM.

The normally closed isolation valves and other passive isolation devices are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges or pipe caps are in place, and closed systems and hydraulic isolator bellows are intact. However, ACTIONS Note 1 and SR 3.6.3.2 and SR 3.6.3.3 contain exceptions to this requirement that allow valves to be open under administrative control. These passive isolation valves/devices are those listed in the LRM.

The containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment," as Type C testing.

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 42-inch purge and exhaust valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment purge and exhaust line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls.

A second Note has been added to provide clarification that, for 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 containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The term "penetration flow path" utilized in the ACTIONS, refers to flow paths through the containment wall that are isolated by at least one containment isolation valve or equivalent (i.e., a closed system, blind flange, etc.). The term "flow paths" used in the ACTIONS is intended to more accurately address containment penetrations that may have more than one flow path. For example, the RCS letdown penetration has three parallel inside power-operated automatic containment isolation valves and a single series outside power-operated automatic containment isolation valve. This penetration has three normal flow paths associated with it. Each inside power-operated automatic containment isolation valve is in series with the single outside containment isolation valve and constitutes a separate flow path. The ACTIONS specifically require the "affected" flow path to be isolated. The ACTIONS may be applied separately to each flow path in this penetration. In the example of the RCS letdown penetration described above, if one of the three inside containment isolation valves is inoperable, it becomes the "affected" flow path and in accordance with the ACTIONS must be isolated. Isolating the

BASES

ACTIONS (continued)

"affected" flow path in this example may be accomplished by closing the inoperable inside containment isolation valve. As the inside and outside containment isolation valves, in this case, are associated with opposite trains, for both the electric power source and the isolation signal, the remaining two flow paths associated with this penetration may remain inservice since the capability to isolate these remaining flow paths, assuming a single active failure, is unaffected. However, if the single outside RCS letdown isolation valve becomes inoperable, the capability to isolate all the flow paths associated with this penetration, assuming a single failure, would no longer exist. Therefore, all flow paths associated with this penetration would be "affected" and the ACTION to isolate the "affected" flow paths would be applicable to all flow paths associated with this penetration.

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

The use of check valves with flow through the valve secured as an isolation barrier per Required Action A.1 is limited to those check valves used as the inside containment isolation valve for the affected penetration flow path. This limitation ensures that the use of check valves as an isolation barrier is consistent with the requirements of 10 CFR 50, Appendix A, Criterion 55 and 56. When using check valves as the isolation barrier, action must be taken to secure flow through the check valve. The action taken to secure flow may use methods such as (but not limited to) the closure of another valve in the affected penetration flow

BASES

ACTIONS (continued)

path. The method used to secure flow to the check valve must not be adversely affected by a single active failure.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that 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 isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is not applicable to penetration flow paths addressed by Condition C. For penetration flow paths with only one containment isolation valve and a closed system inside containment, Condition C provides the appropriate actions when the single containment isolation valve associated with this type of penetration flow path is inoperable.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these devices once they have been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

BASES

ACTIONS (continued)

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with one inoperable containment isolation valve connected to a closed system inside containment. Containment penetrations that credit a closed system for the isolation barrier inside containment are those penetrations that have the inside containment isolation valve identified as a closed system in the LRM. This Note is necessary since this Condition is written to specifically address an inoperable containment isolation valve in those penetration flow paths that use one containment isolation valve connected to a closed system inside containment for the required isolation barriers.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1 and D.2

If the Required Actions and associated Completion Times 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 6 hours and to MODE 5 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 3.6.3.1

Each 42-inch containment purge and exhaust valve is required to be verified deactivated in the closed position for valves outside containment and prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for valves inside containment. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge or exhaust valve. The operation of the containment purge and exhaust valves has not been evaluated to confirm the ability to close during a LOCA in time to

BASES

SURVEILLANCE REQUIREMENTS (continued)

limit offsite doses. Therefore, these valves are required to be deactivated in the closed position during MODES 1, 2, 3, and 4. A containment purge or exhaust valve that is deactivated in the closed position must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing control power to the valve operator. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.3.2

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed

BASES

SURVEILLANCE REQUIREMENTS (continued)

within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.4

Verifying that the isolation time of each automatic power operated containment isolation valve required to be closed during accident conditions (i.e., Containment Isolation Phase A or B signal) is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that each valve required to automatically isolate on a Containment Isolation Phase A or B signal will isolate in a time period consistent with the assumptions of the safety analyses. The required isolation times are specified in the LRM. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.3.5

Automatic power operated containment isolation valves required to be closed during accident conditions close on a Phase A or Phase B containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic power operated containment isolation valve required to be closed during accident conditions will actuate to its isolation position on a Phase A or Phase B containment isolation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Chapter 14 (Unit 1), and UFSAR, Chapter 15 (Unit 2).
2. Regulatory Guide 1.183, July 2000.
3. Standard Review Plan 6.2.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Quench Spray System. In addition, the lower containment pressure limit provides assurance that sufficient net positive suction head exists for the pumps taking suction from the containment sump during the recirculation phase of operation after a LOCA.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer codes. The worst case LOCA results in a higher containment pressure than the worst case SLB. Thus, the LOCA event bounds the SLB event from the containment peak pressure standpoint (Ref. 1).

The initial pressure assumed in the containment analysis was 14.2 psia. This resulted in a maximum peak pressure from a LOCA of 43.1 psig (Unit 1) and 44.8 psig (Unit 2). The containment analysis (Ref. 1) shows that the maximum peak calculated containment pressure, P_a, results from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA, 43.1 psig (Unit 1) and 44.8 psig (Unit 2), does not exceed the containment design pressure, 45 psig.

The containment was also designed for an internal pressure of 8.0 psia. The inadvertent actuation of the Quench Spray System was evaluated to determine the resulting reduction in containment pressure. The initial pressure condition used in this evaluation was 12.8 psia. This resulted in a minimum pressure inside containment of 11.38 psia, which is within the containment design capability.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Quench Spray System. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit also ensures that sufficient net positive suction head will be available for the Unit 1 recirculation spray and low head safety injection pumps and the Unit 2 recirculation spray pumps.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

BASES

ACTIONS (continued)

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1), and UFSAR, Section 6.2 (Unit 2).

2. 10 CFR 50, Appendix K.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB).

The containment average air temperature limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during unit operations. The total amount of energy to be removed from containment by the Quench and Recirculation Spray systems during post accident conditions is dependent upon the energy released to the containment due to the event. Higher initial temperature results in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Too low a containment temperature would adversely impact the small break LOCA safety analysis assumptions regarding the automatic actuation of Phase B containment isolation on containment high-high pressure. As such, operation with containment temperature outside the LCO limits violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses and is important in establishing environmental qualification (EQ) requirements to assure the required equipment inside containment performs as designed during and after a DBA. The upper limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1). The lower containment temperature limit ensures that Containment Isolation Phase B will be actuated by the Containment Pressure - High High setpoint consistent with the assumptions of the small break LOCA analysis.

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The SLB resulted in the maximum calculated peak containment temperature and containment liner temperature. The Unit 1 SLB that resulted in the peak containment temperature occurred at

BASES

APPLICABLE SAFETY ANALYSES (continued)

100% RTP, with the worst case single failure of a main steam check valve. The Unit 1 SLB that resulted in the peak containment liner temperature occurred at 30% RTP, with the worst case single failure of a main steam check valve. The Unit 2 SLB that resulted in the peak containment temperature occurred at 100% RTP, with the worst case single failure of a main steam isolation valve. The Unit 2 SLB that resulted in the peak containment liner temperature occurred at 0% RTP, with the worst case single failure of a main steam isolation valve.

The initial upper containment average air temperature assumed in the design basis analyses (Ref. 1) is 108°F. This resulted in a maximum containment air temperature of 355.9°F (for Unit 1) and 345.6°F (for Unit 2) and a maximum containment liner temperature of 257.9°F (for Unit 1) and 249.4°F (for Unit 2). The design temperature of the containment liner is 280°F.

The containment air temperatures resulting from DBAs are used to establish EQ requirements (Ref. 2) for equipment inside containment. The EQ requirements provide assurance the equipment inside containment required to function during and after a DBA performs as designed during the adverse environmental conditions resulting from a DBA. Air temperature profiles (containment air temperature vs time) are calculated for each DBA to establish EQ design requirements for the equipment inside containment. The equipment inside containment required to function during and after a DBA is confirmed to be capable of performing its design function under the applicable EQ requirement (i.e., air temperature profile). Maintaining the initial containment air temperature within the required limits preserves the initial conditions assumed in the accident analyses which limits the containment air temperature and pressure resulting from various DBAs. Limiting the containment air temperature and pressure that result from various DBAs ensures the equipment inside containment will continue to perform as designed during and after a DBA. Therefore, it is concluded that the calculated transient containment air temperature resulting from various DBAs, including the most limiting temperature from a SLB, are acceptable.

The upper temperature limit is also used in the depressurization evaluation to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Quench Spray System (Ref. 3).

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressure is a LOCA. The temperature limit is used in this analysis to ensure that in the event of an accident the design containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, with an initial containment average air temperature within the LCO temperature limits, the resultant accident temperature profile assures that the containment structural temperature is maintained below its design temperature and that required safety related equipment will continue to perform their function.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limits of the LCO, it must be restored to within limits within 8 hours. This Required Action is necessary to return operation to within the bounds of the 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 containment average air temperature cannot be restored to within its 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 6 hours and to MODE 5 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limits ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1), and UFSAR, Section 6.2 (Unit 2).
2. 10 CFR 50.49.
3. UFSAR, Section 5.2 (Unit 1) and UFSAR, Section 6.2 (Unit 2).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Quench Spray (QS) System

BASES

BACKGROUND

The QS System is designed to provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. The QS System, operating in conjunction with the Recirculation Spray (RS) System, is designed to cool and depressurize the containment structure to less than 50% of the peak calculated containment pressure within 24 hours following a Design Basis Accident (DBA). Reduction of containment pressure and the iodine removal capability of the spray limit the release of fission product radioactivity from containment to the environment in the event of a DBA.

The QS System consists of two separate trains of adequate capacity, each capable of meeting the design bases. Each train includes a spray pump, spray headers, nozzles, valves, and piping. The two Unit 2 containment spray ring headers are shared by both QS System trains. Each train is powered from a separate Engineered Safety Features (ESF) bus. The refueling water storage tank (RWST) supplies borated water to the QS System.

The QS System is actuated either automatically by a Containment High-High pressure signal or manually. The QS System provides a spray of cold borated water into the upper regions of containment to reduce the containment pressure and temperature during a DBA. Each train of the QS System provides adequate spray coverage to meet the system design requirements for containment heat and iodine fission product removal. The Unit 1 QS System also provides flow to the containment sump to improve the net positive suction head available to the RS System pumps.

The Containment Sump pH Control System provides sodium tetraborate (NaTB) to the containment sump. The NaTB added to the containment sump water ensures an alkaline pH for the solution recirculated in the containment sump. Control of the containment sump water pH minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The QS System is a containment ESF system. It is designed to ensure that the heat removal capability required during the post accident period can be attained. Operation of the QS System and RS System provides the required heat removal capability to limit post accident conditions to

BASES

BACKGROUND (continued)

less than the containment design values and depressurize the containment structure to less than 50% of the peak calculated containment pressure within 24 hours following a DBA.

The QS and RS Systems limit the temperature and pressure that could be expected following a DBA and ensures that containment leakage is maintained consistent with the accident analysis.

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed, with respect to the worst case single active failure. The appropriate single failure is assumed in the safety analysis. However, the maximum calculated peak containment pressure results from a LOCA postulated to occur in the RCS hot leg. The calculated peak containment pressure from this location occurs during the blowdown phase, prior to the actuation of any safety related equipment, consequently there is no single failure assumed in this analysis. The SLB resulted in the maximum calculated peak containment temperature and containment liner temperature. The Unit 1 SLB that resulted in the peak containment temperature occurred at 100% RTP, with the worst case single failure of a main steam check valve. The Unit 1 SLB that resulted in the peak containment liner temperature occurred at 30% RTP, with the worst case single failure of a main steam check valve. The Unit 2 SLB that resulted in the peak containment temperature occurred at 100% RTP and peak containment liner temperature occurred at 0% RTP, with the worst case single failure of a main steam isolation valve.

During normal operation, the containment internal pressure is maintained within the limits of LCO 3.6.4, "Containment Pressure." Maintaining containment pressure within the required limits during operation ensures the capability to depressurize the containment to less than 50% of the peak calculated containment pressure within 24 hours after a DBA.

The DBA analyses (Ref. 1) show that the maximum peak containment pressure of 43.1 psig (Unit 1) and 44.8 psig (Unit 2) results from the LOCA analysis and is calculated to be less than the containment design pressure. The maximum peak containment atmosphere temperature of 355.9°F (Unit 1) and 345.6°F (Unit 2) and the maximum containment liner temperature of 257.9°F (Unit 1) and 249.4°F (Unit 2) results from the SLB analysis. The containment liner design temperature is 280°F. The containment air temperatures resulting from DBAs are used to establish

BASES

APPLICABLE SAFETY ANALYSES (continued)

EQ requirements (Ref. 2) for equipment inside containment. The EQ requirements provide assurance the equipment inside containment required to function during and after a DBA performs as designed during the adverse environmental conditions resulting from a DBA. Air temperature profiles (containment air temperature vs time) are calculated for each DBA to establish EQ design requirements for the equipment inside containment. The equipment inside containment required to function during and after a DBA is confirmed to be capable of performing its design function under the applicable EQ requirement (i.e., air temperature profile). Therefore, it is concluded that the calculated transient containment atmosphere temperatures resulting from various DBAs, including the most limiting temperature from a SLB, are acceptable.

The modeled QS System actuation from the containment analysis is based upon a response time associated with exceeding the Containment High-High pressure signal setpoint to achieving full flow through the quench spray nozzles. A delayed response time initiation provides conservative analyses of peak calculated containment temperature and pressure responses. The QS System total response time is specified in the Licensing Requirements Manual (LRM) and includes the signal delay, diesel generator startup time, and system startup time.

For certain aspects of accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 3).

Inadvertent actuation of the QS System is also evaluated, and the resultant reduction in containment pressure is calculated. The maximum calculated reduction in containment pressure does not reduce containment pressure below the minimum containment design pressure of 8.0 psia.

The QS System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

During a DBA, one train of the QS System is required to provide the heat removal capability assumed in the safety analyses for containment. To ensure that requirements for heat removal are met, two QS System trains must be OPERABLE with power from two safety related, independent power supplies. Therefore, in the event of an accident, at least one train in each system will operate, assuming that the worst case single active failure occurs.

Each QS System includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the QS System.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the QS System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If one QS train is inoperable, it must be restored to OPERABLE status within 72 hours. The components in this degraded condition are capable of providing 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

B.1 and B.2

If the Required Action and associated Completion Time 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 6 hours and to MODE 5 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment of manual, power operated, and automatic valves, excluding check valves, in the QS System provides assurance that the proper flow path exists for QS System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to being secured. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.2

Verifying that each QS System pump's developed head at the flow test point is greater than or equal to the required developed head ensures that QS System pump performance has not degraded during the cycle. The term "required developed head" refers to the value that is assumed in the Containment Integrity Safety Analysis for the QS pump's developed head at a specific flow point. This value for the required developed head at a flow point is defined as the Minimum Operating Point (MOP) in the Inservice Testing (IST) Program. The verification that the pump's developed head at the flow test point is greater than or equal to the required developed head is performed by using a MOP curve. The MOP curve is contained in the IST Program and was developed using the required developed head at a specific flow point as a reference point. From the reference point, a curve was drawn which is a constant percentage below the current pump performance curve. Based on the MOP curve, a verification is performed to ensure that the pump's developed head at the flow test point is greater than or equal to the required developed head. Flow and differential head are normal test parameters of centrifugal pump performance required by the ASME Code (Ref. 4). Since the QS System pumps cannot be tested with flow through the spray headers, they are tested on bypass flow. This test confirms one point on the pump design 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3 and SR 3.6.6.4

These SRs ensure that each QS automatic valve actuates to its correct position and each QS pump starts upon receipt of an actual or simulated containment spray actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.5

This SR is performed following maintenance when the potential for nozzle blockage has been determined to exist by an engineering evaluation. The required evaluation will also specify an appropriate test method for determining the spray header OPERABILITY. This SR ensures that each spray nozzle is unobstructed and that spray coverage of the containment during an accident is not degraded. Due to the passive nature of the design of the nozzle, a test following maintenance that results in the potential for nozzle blockage is considered adequate to detect obstruction of the nozzles.

REFERENCES

1. UFSAR, Chapter 14 (Unit 1), and UFSAR, Section 6.2 (Unit 2).
2. 10 CFR 50.49.
3. 10 CFR 50, Appendix K.
4. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Recirculation Spray (RS) System

BASES

BACKGROUND

The RS System, operating in conjunction with the Quench Spray (QS) System, is designed to limit the post accident pressure and temperature in the containment to less than the design values and to depressurize the containment structure to less than 50% of the peak calculated containment pressure within 24 hours following a Design Basis Accident (DBA). The reduction of containment pressure and the removal of iodine from the containment atmosphere by the spray limit the release of fission product radioactivity from containment to the environment in the event of a DBA.

The RS System consists of two separate trains of adequate capacity, each capable of meeting the design and accident analysis bases.

Unit 1

The Unit 1 Recirculation Spray System consists of four 50 percent capacity subsystems (2 per train). Each subsystem is composed of a spray pump, associated heat exchanger and flow path. Two of the recirculation spray pumps are located outside containment (RS-P-2A and RS-P-2B) and two pumps are located inside containment (RS-P-1A and RS-P-1B). The flow path from each pump is piped to an individual 180° recirculation spray header inside containment. Train "A" electrical power and river water is supplied to the subsystems containing recirculation spray pumps RS-P-1A and RS-P-2A. Train "B" electrical power and river water is supplied to the subsystems containing recirculation spray pumps RS-P-1B and RS-P-2B.

Unit 2

The Unit 2 Recirculation Spray System consists of four 50 percent capacity subsystems (2 per train). Each subsystem is composed of a spray pump, associated heat exchanger and flow path. All recirculation spray pumps are located outside containment and supply flow to two 360° recirculation spray ring headers located in containment. One spray ring is supplied by the "A" train subsystem containing recirculation spray pump 2RSS-P21A and the "B" train subsystem containing recirculation spray pump 2RSS-P21D with the other spray ring being supplied by the "A" train subsystem containing recirculation spray pump 2RSS-P21C and the "B" train subsystem containing recirculation spray pump 2RSS-P21B. When the water in the refueling water storage tank has reached a predetermined Level Extreme Low setpoint, the C and D subsystems are automatically switched to the cold leg recirculation mode of Emergency Core Cooling System (ECCS) operation.

BASES

BACKGROUND (continued)

Each train of the RS System provides adequate spray coverage to meet the system design requirements for containment heat and iodine fission product removal.

The RS System provides a spray of subcooled water into the upper regions of containment to reduce the containment pressure and temperature during a DBA. At Unit 1, upon receipt of a coincident High High Containment Pressure signal (Containment Isolation Phase B (CIB)) and a RWST Level Low signal, the Unit 1 RS-P-1A and RS-P-1B pumps immediately start. The Unit 1 RS-P-2A and RS-P-2B pumps start after a 15 ± 3 second time delay for emergency generator loading considerations. At Unit 2, upon receipt of a High-High Containment Pressure signal (Containment Isolation Phase B (CIB)) coincident with an RWST Level Low, all the Unit 2 RS pumps start immediately following receipt of the actuations signal. The RS pumps take suction from the containment sump and discharge through their respective spray coolers to the spray headers and into the containment atmosphere. Heat is transferred from the containment sump water to river/service water in the spray coolers.

The Containment Sump pH Control System provides sodium tetraborate to the containment sump. The sodium tetraborate added to the containment sump ensures an alkaline pH for the solution recirculated in the containment sump. The resulting alkaline pH of the RS spray (pumped from the sump) enhances the ability of the spray to scavenge iodine fission products from the containment atmosphere. Control of the containment sump water pH minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The RS System is a containment ESF system. It is designed to ensure that the heat removal capability required during the post accident period can be attained. Operation of the QS and RS systems provides the required heat removal capability to limit post accident conditions to less than the containment design values and depressurize the containment structure to less than 50% of the peak calculated containment pressure within 24 hours following a DBA.

The RS System limits the temperature and pressure that could be expected following a DBA and ensures that containment leakage is maintained consistent with the accident analysis.

BASES

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients; DBAs are assumed not to occur simultaneously or consecutively. The postulated DBAs are analyzed assuming the worst case single active failure. The appropriate single failure is assumed in the safety analysis. However, the maximum calculated peak containment pressure results from a LOCA postulated to occur in the RCS hot leg. The calculated peak containment pressure from this location occurs during the blowdown phase, prior to the actuation of any safety related equipment, consequently there is no single failure assumed in this analysis. The SLB resulted in the maximum calculated peak containment temperature and containment liner temperature. The Unit 1 SLB that resulted in the peak containment temperature occurred at 100% RTP, with the worst case single failure of a main steam check valve. The Unit 1 SLB that resulted in the peak containment liner temperature occurred at 30% RTP, with the worst case single failure of a main steam check valve. The Unit 2 SLB that resulted in the peak containment temperature occurred at 100% RTP, with the worst case single failure of a main steam isolation valve (Ref. 1). The Unit 2 SLB that resulted in the peak containment liner temperature occurred at 0% RTP, with the worst case single failure of a main steam isolation valve (Ref. 1).

The peak containment pressure following a high energy line break is affected by the initial total pressure and temperature of the containment atmosphere. Maximizing the initial containment total pressure and average atmospheric temperature maximizes the calculated peak pressure.

During normal operation, the containment internal pressure is maintained within the limits of LCO 3.6.4, "Containment Pressure." Maintaining containment pressure within the required limits during operation ensures the capability to depressurize the containment to less than 50% of the peak calculated containment pressure within 24 hours after a DBA. This capability and the variation of containment pressure are functions of river/service water temperature, RWST water temperature, and the containment air temperature.

The DBA analyses show that the maximum peak containment pressure of 43.1 psig (Unit 1) and 44.8 psig (Unit 2) results from the LOCA analysis and is calculated to be less than the containment design pressure. The maximum containment atmosphere temperature of 355.9°F (Unit 1) and 346.6°F (Unit 2) and the maximum containment liner temperature of 257.9°F (Unit 1) and 249.4°F (Unit 2) result from the SLB analysis. The containment liner design temperature is 280°F. The containment air temperatures resulting from DBAs are used to establish equipment qualification (EQ) requirements (Ref. 2) for equipment inside containment.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The EQ requirements provide assurance the equipment inside containment required to function during and after a DBA performs as designed during the adverse environmental conditions resulting from a DBA. Air temperature profiles (containment air temperature vs time) are calculated for each DBA to establish EQ design requirements for the equipment inside containment. The equipment inside containment required to function during and after a DBA is confirmed to be capable of performing its design function under the applicable EQ requirement (i.e., air temperature profile). Therefore, it is concluded that the calculated transient containment atmosphere temperatures resulting from various DBAs, including the most limiting temperature from a SLB, are acceptable. The RS System is not credited in the SLB containment analysis.

The RS System actuation model from the containment analysis is based upon a response time between receipt of the RWST Level Low signal in coincidence with the Containment Pressure High High to achieving full flow through the RS System spray nozzles. A delay in response time initiation provides conservative analyses of peak calculated containment temperature and pressure. The RS System maximum time from coincidence of Containment Pressure High High and RWST Level Low to the start of effective RS spray is 65 seconds for Unit 1 and 77 seconds for Unit 2.

In the case of the Unit 2 RS System, the containment safety analysis models the operation of the system consistent with the system design. The Unit 2 analysis models the RS subsystems starting in the spray mode of operation. When the unit is shifted to the ECCS recirculation mode of operation the containment analysis models a reduction in recirculation spray flow to account for the Unit 2 RS subsystems used for the ECCS low head recirculation function.

For certain aspects of accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 3).

The RS System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

During a DBA, one train (two subsystems) of the RS System is required to provide the minimum heat removal capability assumed in the safety analysis. To ensure that this requirement is met, four RS subsystems must be OPERABLE. This will ensure that at least one train will operate assuming the worst case single failure occurs.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause an increase in containment pressure and temperature requiring the operation of the RS System.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the RS System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

The ACTIONS are modified by a Note that is only applicable to Unit 2. The Note states that in addition to the applicable Required Actions of LCO 3.6.7, "RS System," the Conditions and Required Actions of LCO 3.5.2, "ECCS Operating," or LCO 3.5.3, "ECCS Shutdown," may also be applicable when subsystem(s) containing RS pumps 2RSS-P21C or 2RSS-P21D are inoperable. The Note is provided to identify the relationship of these RS subsystems to the Unit 2 ECCS design. Although the affected subsystems are identified as part of the RS System, they also provide an ECCS safety function (low head recirculation). Therefore, depending on the inoperable condition of these Unit 2 RS subsystems the Actions of one or both of the affected LCOs (RS System and ECCS) may be applicable.

A.1

This Required Action is only applicable to Unit 1. With one of the RS subsystems inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. The components in this degraded condition are capable of providing more than 100% of the heat removal needs (i.e., three of the four RS subsystems remain OPERABLE) after an accident. The 7 day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the RS and QS systems and the low probability of a DBA occurring during this period.

The Action Condition is modified by a Note that identifies the Action as only applicable to Unit 1.

BASES

ACTIONS (continued)

B.1

This Required Action is only applicable to Unit 1. With two of the required RS subsystems inoperable in the one train, at least one of the inoperable RS subsystems must be restored to OPERABLE status within 72 hours. The components in this degraded condition are capable of providing 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capability afforded by the OPERABLE subsystems, a reasonable amount of time for repairs, and the low probability of a DBA occurring during this period.

The Action Condition is modified by a Note that identifies the Action as only applicable to Unit 1.

C.1

This Required Action is only applicable to Unit 2. With a single RS subsystem inoperable or two subsystems inoperable in the same train, the inoperable subsystem(s) must be restored to OPERABLE status within 72 hours. The remaining OPERABLE subsystems in this degraded condition are capable of providing 100% of the required heat removal and ECCS low head recirculation functions after an accident. The 72 hour Completion Time was developed taking into account the redundant capability afforded by the remaining OPERABLE subsystems, a reasonable amount of time for repairs, and the low probability of a DBA occurring during this period.

The Action Condition is modified by a Note that identifies the Action as only applicable to Unit 2.

D.1 and D.2

If the inoperable RS subsystem(s) 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 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time and is reasonable considering that the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

BASES

ACTIONS (continued)

E.1

With three or more RS subsystems inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of manual, power operated, and automatic valves, excluding check valves, in the RS System provides assurance that the proper flow path exists for operation of the RS System. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified as being in the correct position prior to being secured. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.2

Verifying that each RS System pump's developed head at the flow test point is greater than or equal to the required developed head ensures that RS System pump performance has not degraded during the cycle. The term "required developed head" refers to the value that is assumed in the Containment Integrity Safety Analysis for the RS pump's developed head at a specific flow point. This value for the required developed head at a flow point is defined as the Minimum Operating Point (MOP) in the Inservice Testing (IST) Program. The verification that the pump's developed head at the flow test point is greater than or equal to the required developed head is performed by using a MOP curve. The MOP curve is contained in the IST Program and was developed using the required developed head at a specific flow point as a reference point. From the reference point, a curve was drawn which is a constant percentage below the current pump performance curve. Based on the MOP curve, a verification is performed to ensure that the pump's developed head at the flow test point is greater than or equal to the required developed head. Flow and differential head are normal test parameters of centrifugal pump performance required by the ASME Code (Ref. 4). Since the RS System pumps cannot be tested with flow through the spray headers, they are tested on bypass flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.3

These SRs ensure that each automatic valve actuates and that the RS System pumps start upon receipt of an actual or simulated coincident with a Containment Pressure High High/RWST Level Low signal. However, the Unit 1 RS-P-2A and RS-P-2B pumps start after an additional delay of 15 ± 3 seconds for emergency diesel generator loading considerations. The start delay time is also verified for the RS System pumps.

For the RS function of the Containment Spray System, this Surveillance includes a verification of the associated required slave relay operation. Recirculation Spray – Automatic Actuation, Function 2.b.1 in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," does not include a requirement to perform a SLAVE RELAY TEST due to equipment safety concerns if such a test was performed at power. Therefore, verification of the required slave relay OPERABILITY for the Recirculation Spray-Automatic Actuation, Function 2.b.1 in LCO 3.3.2 is included in this Surveillance.

This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.4

This SR is performed following maintenance when the potential for nozzle blockage has been determined to exist by an engineering evaluation. The required evaluation will also specify an appropriate test method for determining the spray ring OPERABILITY. Due to the passive design of the spray rings and their normally dry state, a test following maintenance that results in the potential for nozzle blockage is considered adequate for detecting obstruction of the nozzles.

BASES

REFERENCES

1. UFSAR, Chapter 14 (Unit 1), and UFSAR, Section 6.2 (Unit 2).
2. 10 CFR 50.49.
3. 10 CFR 50, Appendix K.
4. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Containment Sump pH Control System

BASES

BACKGROUND

The Containment Sump pH Control System is a passive system consisting of six baskets of sodium tetraborate (NaTB) that assist in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA) (Refs. 1 and 2).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine absorption capacity of the spray during recirculation from the sump, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms.

The NaTB is stored in baskets in the containment. The initial quench spray is acidic since it is a boric acid solution from the Refueling Water Storage Tank (RWST). As the initial spray solution, and subsequently the recirculation solution, comes in contact with the NaTB, the NaTB dissolves, raising the pH of the sump solution. The final pH of the containment sump water after a DBA is alkaline. Control of the containment sump water pH minimizes the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

BASES

APPLICABLE SAFETY ANALYSES

The Containment Sump pH Control System is essential to the removal of airborne iodine within containment following a DBA (Refs. 3 and 4).

Quench spray consists of a boric acid solution with a spray pH as low as 4.6. As indicated in Standard Review Plan (SRP), Section 6.5.2, Rev 2, "Containment Spray as A Fission Product Cleanup System," fresh sprays (i.e., sprays with no dissolved iodine) are effective at scrubbing elemental iodine and thus a spray additive is unnecessary during the initial injection phase when the spray solution is being drawn from the RWST. As described in the SRP, research has shown that elemental iodine can be scrubbed from the atmosphere with borated water, even at low pH.

Since long-term use of a plain boric acid spray could increase the potential for elemental iodine re-evolution during the recirculation phase of the LOCA, the equilibrium sump solution pH is increased by adding NaTB. Regulatory Guide 1.183 guidance indicates that if the sump water pH is 7 or greater, then a licensee does not need to evaluate re-evolution of iodines for dose consequences. In accordance with the current licensing basis, the dose analysis need not address iodine re-evolution if the sump water pH of 7 or greater is achieved well within 16 hours after the LOCA and is maintained for the duration of the accident. The Containment Sump pH Control System provides a passive safeguard with six baskets of NaTB located in the containment. The basket contents dissolve as the sump fills, raising pH to the required value and maintaining it at or above that value throughout the accident.

The Containment Sump pH Control System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The Containment Sump pH Control System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the six sodium tetraborate storage baskets must be in place and intact (i.e., having no relevant component removed, destroyed or damaged such that the basket cannot perform its function), collectively contain ≥ 188 cubic feet of sodium tetraborate (Unit 1) and ≥ 292 cubic feet of sodium tetraborate (Unit 2) and be capable of providing the required pH adjustment.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Containment Sump pH Control System. The Containment Sump pH Control System assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Containment Sump pH Control System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If the Containment Sump pH Control System is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the recirculation spray solution for corrosion protection and iodine removal is reduced in this condition. The 72 hour Completion Time takes into account that the condition which caused the inoperable system would most likely allow this passive system to continue to provide some capability for pH adjustment and iodine removal, the Containment Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA, and the low probability of the worst case DBA occurring during this period.

B.1 and B.2

If the Containment Sump pH Control System 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 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Containment Sump pH Control System in MODE 3 and 36 hours to reach MODE 5. This is reasonable when considering the reduced pressure and temperature conditions in MODE 3 for the release of radioactive material from the Reactor Coolant System.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

This SR provides visual verification that the six sodium tetraborate storage baskets are in place and intact and collectively contain ≥ 188 cubic feet of sodium tetraborate (Unit 1) and ≥ 292 cubic feet of sodium tetraborate (Unit 2). This amount of NaTB is sufficient to ensure that the recirculation solution following a LOCA is at the correct pH level. No upper limit for quantity of NaTB is specified because pH values calculated assuming the baskets are filled to capacity demonstrated acceptable pH values. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.2

This SR verifies via sampling that the sodium tetraborate contained in the NaTB storage baskets provides the minimum required buffering ability for containment sump borated water. The maximum required buffering ability of the NaTB contained in the storage baskets is not required to be verified because the pH values calculated assuming the baskets are filled to capacity with high density NaTB under minimum boric acid conditions demonstrated acceptable pH values. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.4 (Unit 1).
2. UFSAR, Sections 6.2.2 and 6.5 (Unit 2).
3. UFSAR, Chapter 14 (Unit 1).
4. UFSAR, Chapter 15 (Unit 2).

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser Circulating Water System and Atmospheric Dump Valves, are not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in UFSAR, Section 10.3.1 (Unit 1) and Section 10.3.2 (Unit 2) (Ref. 1). The specified valve lift settings and design relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition (Unit 1 and Unit 2) and Winter 1972 Addenda (Unit 2). The total design relieving capacity for all valves on all of the steam lines is 12.8×10^6 lbs/hr (Unit 1) and 12.7×10^6 lbs/hr (Unit 2) which is approximately 98% (Unit 1) and 97% (Unit 2) of the total secondary steam flow of 13.1×10^6 lbs/hr at 100% RATED THERMAL POWER. The MSSV design includes staggered setpoints, according to Table 3.7.1-2a (Unit 1) and Table 3.7.1-2b (Unit 2) in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine initiated reactor trip. The above capacity (98% or 97% as applicable of rated flow) is sufficient capacity such that main steam pressure does not exceed 110% of the steam generator shell-side design pressure (the maximum pressure allowed by the ASME B&PV Code) for the worst-case loss-of-heat-sink event. This requirement is verified by analysis.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to $\leq$ 110% of design pressure for any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in UFSAR, Section 14.1 (Unit 1) and Section 15.2 (Unit 2) (Ref. 3). Of these, the full power turbine trip without steam dump is the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety analysis demonstrates that the transient response for turbine trip occurring from full power without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. One turbine trip analysis is performed assuming primary system pressure control via operation of the pressurizer relief valves and spray. This analysis demonstrates that the DNB design basis is met. Another analysis is performed assuming no primary system pressure control, but crediting reactor trip on high pressurizer pressure and operation of the pressurizer safety valves. This analysis demonstrates that RCS integrity is maintained by showing that the maximum RCS pressure does not exceed 110% of the design pressure. All cases analyzed demonstrate that the MSSVs maintain Main Steam System integrity by limiting the maximum steam pressure to less than 110% of the steam generator design pressure.

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when either the Overtemperature ΔT or Power Range Neutron Flux-High setpoint is reached. Steam flow to the turbine will not increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to reactor trip, assuming no credit for operation of the atmospheric or condenser steam dump valves. The UFSAR Section 14.1 (Unit 1) and Section 15.1 (Unit 2) safety analysis of the RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The UFSAR safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady-state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the turbine (if available) and the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system overpressurization may be determined by system transient analyses or conservatively arrived at by a simple heat balance calculation. In some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux-High reactor trip function. For example, if more than one MSSV on a single steam generator is inoperable, an uncontrolled RCCA bank withdrawal at power event occurring from a partial power level may result in an increase in reactor power that

BASES

APPLICABLE SAFETY ANALYSES (continued)

exceeds the combined steam flow capacity of the turbine and the remaining OPERABLE MSSVs. Thus, for multiple inoperable MSSVs on the same steam generator it is necessary to prevent this power increase by lowering the Power Range Neutron Flux-High setpoint to an appropriate value. When the Moderator Temperature Coefficient (MTC) is positive, the reactor power may increase above the initial value during an RCS heatup event (e.g., turbine trip). Thus, for any number of inoperable MSSVs, it is necessary to reduce the trip setpoint if a positive MTC may exist at partial power conditions.

The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening, and failure to reclose once opened. The passive failure mode is failure to open upon demand.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The accident analysis requires that five MSSVs per steam generator be OPERABLE to provide overpressure protection for design basis transients occurring at 100.6% RTP. The LCO requires that five MSSVs per steam generator be OPERABLE in compliance with Reference 2, and the DBA analysis.

The OPERABILITY of the MSSVs is defined as the ability to open upon demand within the setpoint tolerances, to relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB, or Main Steam System integrity.

APPLICABILITY

In MODES 1, 2, and 3, five MSSVs per steam generator are required to be OPERABLE to prevent main steam overpressurization.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

BASES

ACTIONS

The ACTIONS are modified by a Note indicating that separate Condition entry is allowed for each MSSV.

With one or more MSSVs inoperable, action must be taken so that the available MSSV relieving capacity meets Reference 2 requirements.

Operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator.

A.1

In the case of only a single inoperable MSSV on one or more steam generators when the Moderator Temperature Coefficient is not positive, a reactor power reduction alone is sufficient to limit primary side heat generation such that overpressurization of the secondary side is precluded for any RCS heatup event. Furthermore, for this case there is sufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Therefore, Required Action A.1 requires an appropriate reduction in reactor power within 4 hours.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as discussed below, with an appropriate allowance for calorimetric power uncertainty.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined by the governing heat transfer relationship from the equation $q = m\Delta h$, where q is the heat input from the primary side, m is the steam mass flow rate, and Δh is the heat of vaporization at the steam relief pressure assuming no subcooled feedwater. For each steam generator, at a specified pressure, the maximum allowable power level is determined as follows:

Maximum Allowable Power Level $\leq (100/Q)\ (w_s h_{fg} N) / K$

where:

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat), MWt

K = Conversion factor, 947.82 (Btu/sec)/MWt

BASES

ACTIONS (continued)

w_s = Minimum total steam flow rate capability of the OPERABLE MSSVs on any one steam generator at the highest OPERABLE MSSV opening pressure, including tolerance and accumulation, as appropriate, lbm/sec. For example, if the maximum number of inoperable MSSVs on any one steam generator is one, then w_s should be a summation of the capacity of the OPERABLE MSSVs at the highest OPERABLE MSSV operating pressure, excluding the highest capacity MSSV. If the maximum number of inoperable MSSVs per steam generator is three, then w_s should be a summation of the capacity of the OPERABLE MSSVs at the highest OPERABLE MSSV operating pressure, excluding the three highest capacity MSSVs.

h_{fg} = Heat of vaporization at the highest MSSV opening pressure, including tolerance and accumulation as appropriate, Btu/lbm.

N = Number of loops in the plant.

For use in determining the % RTP in Required Action A.1, the Maximum NSSS Power calculated above is reduced by 2% RTP to account for calorimetric power uncertainty. This is a conservative value that bounds the uncertainties associated with both the feedwater flow venturis and the Leading Edge Flow Meter.

B.1 and B.2

In the case of multiple inoperable MSSVs on one or more steam generators, with a reactor power reduction alone there may be insufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Furthermore, for a single inoperable MSSV on one or more steam generators when the Moderator Temperature Coefficient is positive the reactor power may increase as a result of an RCS heatup event such that flow capacity of the remaining OPERABLE MSSVs is insufficient. The 4 hour Completion Time for Required Action B.1 is consistent with A.1. An additional 32 hours is allowed in Required Action B.2 to reduce the Power Range Neutron Flux-High reactor trip setpoints. The Completion Time of 36 hours is based on a reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, operating experience to reset all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

BASES

ACTIONS (continued)

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as discussed above, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

To determine the Table 3.7.1-1 Maximum Allowable Power for Required Actions B.1 and B.2 (% RTP), the calculated Maximum NSSS Power is reduced by 9% RTP to account for Nuclear Instrumentation System trip channel uncertainties. An additional conservatism is employed by setting the values equal to the most conservative between the two units, this being the Unit 1 values.

Required Action B.2 is modified by a Note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3 the reactor protection system trips specified in LCO 3.3.1, "Reactor Trip System Instrumentation," provide sufficient protection.

The allowed Completion Times are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging unit systems.

C.1 and C.2

If the Required Actions are not completed within the associated Completion Time, or if one or more steam generators have ≥ 4 inoperable MSSVs, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program and the ASME Code (Ref. 4) requirements.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2a (Unit 1) and Table 3.7.1-2b (Unit 2) specify the required setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift. The lift settings correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. UFSAR, Section 10.3.1 (Unit 1) and Section 10.3.2 (Unit 2).

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.

3. UFSAR, Section 14.1 (Unit 1) and Section 15.2 (Unit 2).

4. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

Unit 1 is designed with main steam trip valves, main steam non-return check valves, and main steam trip bypass valves. The main steam trip valves perform similar functions as the Unit 2 MSIVs and will be herein referred to as MSIVs. The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW steam supply isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Steam Bypass System, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a main steam isolation signal generated by either a Containment Pressure - Intermediate High High, Steam Line Pressure - Negative Rate - High, or Steam Line Pressure - Low function. For Unit 1, the MSIVs fail closed on loss of control air pressure. For Unit 2, the MSIVs fail closed on loss of control or actuation power.

Isolation of the main steam lines provides protection in the event of a steam line break (SLB) inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one steam generator (SG), at most. For an SLB upstream of the MSIVs, inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the steam lines depressurize. For Unit 1, the main steam non-return check valves are designed to automatically prevent reverse flow of steam in the case of accidental pressure reduction in any steam generator or its piping. If a steam line breaks between a non-return valve and a steam generator, the affected steam generator continues to blowdown while the non-return valve in the line prevents significant blowdown from the other steam generators. For Unit 2, which does not have main steam non-return check valves, steam line isolation will also mitigate the effects of a feed line break and ensures a source of steam for the turbine driven AFW pump during a feed line break.

BASES

BACKGROUND (continued)

Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the UFSAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large SLB inside containment, discussed in the UFSAR, Chapter 14 (Unit 1) and Section 6.2 (Unit 2) (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the UFSAR, Section 14.2.5.1 (Unit 1) and Section 15.1.5 (Unit 2) (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

The limiting case for the containment analysis is the SLB inside containment, with offsite power available, and failure of the main steam non-return check valve (Unit 1) or the MSIV (Unit 2) on the affected steam generator to close. At lower powers, the steam generator inventory and pressure are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to reverse flow and failure of the main steam non-return check valve (Unit 1) or the MSIV (Unit 2) to close, the additional mass and energy in the steam headers downstream from the other MSIVs contribute to the total release. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB at hot zero power is the limiting case for a return to power event. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include failure of an MSIV to close.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. An HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. For Unit 2, the MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that three MSIVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on a manual and automatic isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the limits specified in Regulatory Guide 1.183 (Ref. 4).

BASES

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed and de-activated, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4 the steam generator energy is low and the MSIVs are not required to support the safety analysis due to the low probability of a design basis accident.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

The 8 hour Completion Time is greater than that allowed for most containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional means for containment isolation.

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition C would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

BASES

ACTIONS (continued)

The 8 hour Completion Time is consistent with that allowed in Condition A.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is within the limit specified in the Licensing Requirements Manual (Ref. 5). The MSIV total response time (signal generation plus MSIV closure time) is assumed in the accident analyses. The MSIVs should not be tested at power due to the risk of a valve closure when the unit is generating power. As MSIVs are not typically tested at power, they are exempt from the ASME Code (Ref. 6) requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

This test is allowed to be conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.2

This SR verifies that each MSIV can close on an actual or simulated automatic and manual actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.3.
2. UFSAR, Chapter 14 (Unit 1) and Section 6.2 (Unit 2).
3. UFSAR, Section 14.2.5.1 (Unit 1) and Section 15.1.5 (Unit 2).
4. Regulatory Guide 1.183, July 2000.
5. Licensing Requirements Manual (LRM) for BVPS Unit 1 and Unit 2.
6. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs) and Main Feedwater Regulation Valves (MFRVs) and MFRV Bypass Valves

BASES

BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MFRVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFIVs or MFRVs and MFRV bypass valves terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs or MFRVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs or MFRVs and MFRV bypass valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The MFIVs isolate the nonsafety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFIV and one MFRV and MFRV bypass valve, are located on each MFW line, outside of containment. The MFIVs and MFRVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MFIV or MFRV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

The MFIVs and MFRVs and MFRV bypass valves close on receipt of a safety injection or steam generator water level - high high signal. The MFRVs will also close on receipt of a T_{avg} - Low coincident with reactor trip (P-4). They may also be actuated manually. In addition to the MFIVs and the MFRVs and MFRV bypass valves, a check valve outside containment is available. The check valve provides the first pressure boundary for the addition of AFW to the intact loop and prevents backflow in the feedwater line should a break occur upstream of the valve.

A description of the MFIVs and MFRVs is found in the UFSAR, Section 10.3.5 (Unit 1) and Section 10.4.7 (Unit 2) (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the MFIVs and MFRVs is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFIVs or MFRVs and MFRV bypass valves, are relied on to terminate a SLB for core response analysis and excess feedwater event upon the receipt of a steam generator water level - high high signal.

Failure of an MFIV, MFRV, or the MFRV bypass valves to close following an SLB or FWLB can result in additional mass being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following a SLB or FWLB event.

The MFIVs and MFRVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that the MFIVs, MFRVs, and the MFRV bypass valves will isolate MFW flow to the steam generators, following an FWLB or main steam line break.

This LCO requires that three MFIVs and three MFRVs and MFRV bypass valves be OPERABLE. The MFIVs and MFRVs and the MFRV bypass valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. A feedwater isolation signal on steam generator water level - high high is relied on to terminate an excess feedwater flow event, failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MFIVs and MFRVs and the MFRV bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. In MODES 1, 2, and 3, the MFIVs and MFRVs and the MFRV bypass valves are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed and de-activated or isolated by a closed manual valve, they are already performing their safety function.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs, MFRVs, and the MFRV bypass valves are not required to be OPERABLE.

BASES

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one MFIV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

B.1 and B.2

With one MFRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRVs, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

BASES

ACTIONS (continued)

C.1 and C.2

With one MFRV bypass valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRV bypass valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

D.1

With two inoperable in series valves in the same flow path, there may be no redundant system to operate automatically and perform the required safety function. The containment can be isolated with the failure of two valves in parallel in the same flow path. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MFIV or MFRV, or otherwise isolate the affected flow path.

E.1 and E.2

If the MFIV(s) and MFRV(s) and the MFRV bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MFIV, MFRV, and MFRV bypass valve is within the limit(s) specified in the Licensing Requirements Manual (LRM) (Ref. 2). The total response times (signal generation plus valve closure time) are assumed in the SLB or FWLB accident analyses.

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

SR 3.7.3.2

This SR verifies that each MFIV, MFRV, and MFRV bypass valve can close on an actual or simulated actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.3.5 (Unit 1) and Section 10.4.7 (Unit 2).

2. Licensing Requirements Manual (LRM) for BVPS Unit 1 and Unit 2.

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND

The ADV lines required OPERABLE include the three atmospheric relief valves (one per steam generator (SG)) and the associated block (isolation) valves and for Unit 2 only, one residual heat release valve and its block valve and individual SG isolation valves. The Unit 2 residual heat release valve and all its associated isolation valves are counted as one of the required ADV lines for Unit 2. As discussed in the UFSAR, Section 10.3 (Ref. 1), the atmospheric relief valves and the residual heat release valve provide a method of removing core decay heat and cooling the unit to Residual Heat Removal (RHR) System entry conditions should the preferred heat sink via the condenser steam dump valves not be available.

Each ADV line has a block valve. The block valves are normally open manual valves. The block valves can be used for isolating an ADV line if necessary. However, due to time constraints in the safety analysis, the ADV block valves must remain open for an ADV line to be considered OPERABLE. In addition to the block valve described above, the Unit 2 residual heat release valve has three normally open isolation valves (one for each SG). The individual SG isolation valves are used to isolate a faulted SG so the Unit 2 residual heat release valve can be used for accident mitigation. In order for the Unit 2 residual heat release valve ADV line to be OPERABLE, the individual SG isolation valves must be maintained open with the capability of being manually closed.

The Unit 1 ADVs are DC powered air operated valves utilizing a non-safety related air system. The Unit 1 ADVs can normally be operated from the control room. However, in order to meet the assumptions of the operational assessment used to evaluate single failure concerns, the Unit 1 ADVs must be capable of being operated locally as well as from the control room in order to be considered OPERABLE.

The Unit 2 ADVs have an electro-hydraulic operator that can be operated from the control room. Each Unit 2 atmospheric relief valve is powered by the same emergency AC train power. The Unit 2 residual heat release valve is powered by the other emergency AC train. In order to meet the assumptions of the applicable safety analysis, the Unit 2 ADVs (including the residual heat release valve) must be capable of being operated locally as well as from the control room in order to be considered OPERABLE.

BASES

BACKGROUND (continued)

The ADVs have a non-safety related automatic pressure control capability. However, the only function of the ADVs required by the safety analyses (and this Technical Specification) is the ability to cool down the plant following a Design Basis Accident (DBA).

APPLICABLE SAFETY ANALYSES

In the accident analysis presented in the UFSAR (Ref. 2), the ADVs may be used by the operator to cool down the unit to RHR entry conditions for accidents accompanied by a loss of offsite power.

The design bases of the ADVs are established by the capability to cool the unit to RHR System entry conditions. For the recovery from a design basis steam generator tube rupture (SGTR) accident, the operator is required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the faulted steam generator. The time required to terminate the primary to secondary break flow for the design basis SGTR accident is more critical than the time required to cool down to RHR System entry conditions for this event and for other Design Basis Accidents (DBAs). Thus, the SGTR is the limiting event for the ADVs.

For Unit 1, three ADVs with associated flow paths and isolation valves are required OPERABLE. Due to the design of the Unit 1 residual heat release valve, it can not be isolated from a SG with a ruptured tube. Therefore, the Unit 1 residual heat release valve is not used to mitigate a SGTR due to the dose requirements of the accident analysis. The requirement for three OPERABLE ADV lines provides assurance that a single active failure of one ADV line or a single active failure of the instrument air supply will not prevent the mitigation of a SGTR accident.

The Unit 1 operational assessment used to evaluate the single failures described above also assumes that one ADV is lost to the faulted SG. In the case where the instrument air supply is available and an active failure of one of the remaining ADVs is assumed, the operational assessment assumes the remaining ADV is operated from the control room to successfully mitigate the SGTR accident. In the case where the active failure is a loss of instrument air, and ADV operation is delayed, the operational assessment assumes the two remaining ADVs are operated by local manual control to successfully mitigate the SGTR accident. Therefore, the Unit 1 ADVs must be capable of both remote and local manual operation to be considered OPERABLE. The Unit 1 operational assessment does not include a specific time to manually unblock an ADV. Therefore, the Unit 1 ADV block valves must remain open for the ADV lines to be considered OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For Unit 2, four ADVs with associated flow paths and isolation valves are required OPERABLE to satisfy the SGTR accident analysis assumptions of a single active failure and loss of offsite power. Requiring four Unit 2 ADVs OPERABLE assures that two ADVs will remain OPERABLE for the SGTR analysis overfill case (i.e., one ADV lost to the faulted SG and one ADV lost to a single active failure). Additionally, requiring four Unit 2 ADVs OPERABLE assures that three ADVs will remain OPERABLE for the SGTR radiological dose case. The radiological dose case includes the loss of one ADV as a single active failure (i.e., the ADV on the faulted SG fails open).

The Unit 2 SGTR analysis requires that two ADVs (overfill case) or three ADVs (bounding dose case) remain OPERABLE to mitigate the accident within the assumed time frame. All other radiological dose cases only require two ADVs, since a longer cooldown does not have as great an impact on SGTR doses as a failed open ADV on the faulted SG.

Furthermore, in order to assure the SGTR accident can be mitigated within the Unit 2 analysis requirements, the ADVs must be capable of both remote and local manual operation. In addition, the Unit 2 safety analysis does not include additional time to manually unisolate a blocked ADV. Therefore, an ADV line with a closed block valve is considered inoperable. The Unit 2 safety analysis does account for the time it takes to manually isolate the faulted SG from the Unit 2 residual heat release valve so that the ADV line can be used to meet the accident analysis requirements. Therefore, the individual normally open SG isolation valves associated with the Unit 2 residual heat release valve must also be maintained open with the capability of being manually closed for the Unit 2 residual heat release valve ADV line to be OPERABLE.

The ADVs are equipped with block valves in the event an ADV spuriously fails to open or fails to close during use. The ADVs, as well as the RHRV, at each unit may pass some amount of steam leakage, since the SGTR radiological analyses for BVPS-1 and BVPS-2 include a steam flow margin factor. Such leakage may pass through the Main Steam Safety Valves, as well. TS 3.7.1 OPERABILITY of the MSSVs is not affected, since these valves are not discussed or credited in SGTR accident mitigation. Any observed steam leakage would have to be measurable on the installed Main Steam Flow System instruments (above instrument accuracy) to be considered significant.

The ADVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The LCO requires three Unit 1 ADV lines and four Unit 2 ADV lines to be OPERABLE. The ADV lines required OPERABLE include the three atmospheric relief valves (one per SG) and the associated block (isolation) valves and for Unit 2 only, one residual heat release valve and its block valve and individual SG isolation valves. The Unit 2 residual heat release valve and all its associated isolation valves are counted as one ADV line for Unit 2. The number of ADV lines required OPERABLE is consistent with each Unit's design and the safety analyses requirements described above.

An OPERABLE ADV line is capable of providing controlled relief of the main steam flow and capable of fully opening and closing. In order to be OPERABLE, the ADVs (including the Unit 2 residual heat release valve) must be capable of remote manual and local manual operation. Also, the block valve associated with each ADV line must be open for the line to be considered OPERABLE. In addition to the above requirements, the three individual SG isolation valves associated with Unit 2 residual heat release valve must be open and capable of being manually closed for the residual heat release valve ADV line to be considered OPERABLE.

The block valves associated with each ADV line must be OPERABLE to isolate a failed open ADV line. In addition, the three individual SG isolation valves associated with the Unit 2 residual heat release valve ADV line must be OPERABLE to enable a faulted SG to be isolated from the residual heat release valve ADV line.

Failure to meet the LCO could result in the inability to cool the unit under the limiting accident conditions within the time limit assumed in the applicable safety analyses described above.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the ADVs are required to be OPERABLE.

In MODE 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one required ADV line inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ADV lines, a nonsafety grade backup in the condenser steam dump valves, and MSSVs.

BASES

ACTIONS (continued)

B.1

With two or more ADV lines inoperable, action must be taken to restore all but one ADV line to OPERABLE status. Since the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ADV lines, based on the availability of the condenser steam dump valves and MSSVs, and the low probability of an event occurring during this period that would require the ADV lines.

C.1 and C.2

If the ADV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon steam generator for heat removal, within 24 hours. In this condition, the unit utilizes RHR for cooling. Therefore, operation may continue with one or more ADV lines inoperable because the RCS cooling function required to mitigate a SGTR event would be accomplished by the RHR System. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened and throttled through their full range. This SR ensures that the ADVs are tested through a full control cycle at least once per fuel cycle. The requirement to stroke the valve through the full range of operation may be accomplished by remote manual control. In addition, this Surveillance must also verify the capability to locally operate each ADV. The verification of local operation does not require that the ADV be stroked through the full range of travel (i.e., if the valve is stroked full open and closed by remote manual operation, the capability to operate the ADV locally may be verified by observing valve stem movement). The ADVs must be capable of both remote and local manual operation in order to be considered OPERABLE. Performance of inservice testing or use of an ADV during a unit cooldown may satisfy this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.2

The function of the block valve is to isolate a failed open ADV. Cycling the block valve closed and open demonstrates its capability to perform this function. Performance of maintenance or other testing that results in cycling these valves including the use of the block valve during unit cooldown may satisfy this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.4.3

The function of the individual SG isolation valves associated with the Unit 2 residual heat release valve is to isolate the residual heat release valve from a SG with a ruptured tube. Isolating the SG with a ruptured tube minimizes the resulting dose when the residual heat release valve is used for SGTR accident mitigation. Cycling these isolation valves closed and open demonstrates the capability to perform this function. Performance of maintenance or other testing that results in cycling these valves, including the use of the isolation valve during unit cooldown may satisfy this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Surveillance is modified by a Note that states the Surveillance is only applicable to Unit 2. The Note is necessary because the corresponding Unit 1 residual heat release valve is not required OPERABLE by LCO 3.7.4. Only the Unit 2 residual heat release valve is required OPERABLE by LCO 3.7.4. This is because Unit 2 requires the additional relief capacity provided by this valve for accident mitigation and the Unit 2 residual heat release valve has individual SG isolation valves that allow it to be isolated from a faulted SG so it can be used for accident mitigation.

REFERENCES

1. UFSAR, Section 10.3.

2. UFSAR, Section 14 (Unit 1) and UFSAR Section 15 (Unit 2).

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators (SGs) to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply.

The AFW System consists of two motor driven pumps and one steam turbine driven pump configured into three trains. The AFW System design is such that it can perform its function following a total loss of normal feedwater and the single failure of an AFW pump. Any two of the three AFW pumps are capable of supplying the required feedwater flow assumed in the accident analyses. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system. Each motor driven AFW pump is powered from an independent Class 1E power supply and each pump feeds all three SGs. The steam turbine driven AFW pump receives steam from a minimum of two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the steam requirements for the turbine driven AFW pump. For Unit 1, the turbine driven AFW pump steam feed lines from each of the three main steam lines combine to form one supply header. The single header then splits into two parallel paths with one Train "A" operated and one Train "B" operated isolation valve on each pathway. The two parallel paths then combine into one header which supplies steam to the turbine driven AFW pump. For Unit 2, the turbine driven AFW pump steam feed lines from each of the three main steam lines contain two in-line series solenoid operated isolation valves. Downstream of the series isolation valves, the three lines combine to form one main header. The main header then supplies the turbine driven AFW pump. Although the turbine driven pump in each Unit is capable of receiving the required steam supply from any one of the three main steam lines, only two steam feed lines are required OPERABLE.

The flow path from the primary plant demineralized water storage tank (PPDWST) (WT-TK-10 (Unit 1) and 2FWE-TK210 (Unit 2)) to the SGs consists of individual supply lines to each of the three AFW pumps. Each motor driven AFW pump is connected to its train related supply header. In addition, for Unit 1, each motor driven AFW pump has the ability to be aligned to the opposite train header. The turbine driven pump can also be aligned to either the Train "A" or "B" supply header.

BASES

BACKGROUND (continued)

The Train "A" and "B" supply headers branch out to each SG feedwater line via three normally open remotely operated valves arranged in parallel flow paths. The individual Train "A" and "B" supply header flow paths are then combined into one common feedwater line injection header for each SG. The common feedwater injection headers each contain a check valve. Each common feedwater injection header supplies a separate SG via the normal feedwater header downstream of the feedwater isolation valves.

The SGs function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the SGs via the main steam safety valves (MSSVs) or atmospheric dump valves (ADVs). If the main condenser is available, steam may be released via the steam dump valves.

The AFW System is capable of supplying feedwater to the SGs during normal unit startup, shutdown, and hot standby conditions.

During a normal plant cooldown, one pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is designed to supply sufficient water to the SG(s) to remove decay heat with SG pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs.

The AFW System actuates automatically on SG water level – low low by the ESFAS (LCO 3.3.2). The system also actuates on Undervoltage - RCP bus (turbine driven AFW pump only), safety injection, and trip of all running MFW pumps (motor driven AFW pumps only).

The AFW System is discussed in the UFSAR, Section 10.3.5.2.2 (Unit 1) and Section 10.4.9 (Unit 2) (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the SG to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the SGs at pressures corresponding to the lowest MSSV set pressure plus 1%.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In addition, the AFW System must supply enough makeup water to replace the SG secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accident (DBA) for the AFW System are loss of normal feedwater and feedwater line break.

For the loss of normal feedwater and feedwater line break, the analyses are performed assuming loss of offsite power coincident with reactor trip. The limiting single active failure is the failure of the turbine driven AFW pump, which requires both remaining motor driven AFW pumps to be OPERABLE.

The AFW System design is such that it can perform its function following a feedwater line break (FWLB) between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of an AFW pump. Sufficient flow would be delivered to the two intact SGs by the two remaining AFW pumps. No pump runout occurs due to the cavitating venturis. Two motor driven pumps or one motor driven pump combined with the turbine driven pump can deliver the design bases flows to the intact SGs during a FWLB. There are two distinct flows that must be delivered during a FWLB. They are prior to fault isolation (i.e., during the first 15 minutes) and subsequent to fault isolation via operator action. Any two of the three AFW pumps are capable of supplying the flows required prior and subsequent to fault isolation.

The AFW System design is such that it can perform its function following a total loss of normal feedwater. Any two of the three AFW pumps are capable of supplying the required flows to the three intact SGs during this event.

With one feedwater injection header inoperable, an insufficient number of SGs are available to meet the feedline break analysis. This analysis assumes AFW flow will be provided to the two remaining intact feedwater lines. Should a feedline break occur on one of the OPERABLE feedwater headers with one feedwater injection header already inoperable, the plant could no longer meet its safety analysis.

The ESFAS automatically actuates the AFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the SGs during loss of power. Power operated valves are provided for each AFW line to control the AFW flow to each SG.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three AFW pumps in three trains are required to be OPERABLE to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

In addition, the LCO requires three feedwater injection headers to be OPERABLE. The common feedwater line injection headers must be OPERABLE to ensure the required AFW trains have the capability of providing flow to all three SGs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE.

OPERABILITY of the three feedwater trains shall consist of:

a. One motor driven AFW pump with a flow path from the PPDWST to each feedwater line injection header via the Train "A" supply header.

b. One motor driven AFW pump with a flow path from the PPDWST to each feedwater line injection header via the Train "B" supply header.

c. One turbine driven AFW pump capable of being powered from two steam supplies with a flow path from the PPDWST to each feedwater line injection header via the designated train supply header. Only two out of three steam supply lines to the turbine driven pump must be OPERABLE to provide the required redundancy.

The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE.

BASES

LCO (continued)

The LCO is modified by a Note indicating that one AFW train, which includes a motor driven pump and the required feedwater injection header(s), are required to be OPERABLE in MODE 4. One motor driven AFW train and the feedwater injection header(s) required to support flow to the SG(s) being relied on for decay heat removal are sufficient in MODE 4. The other AFW trains and injection headers are not required OPERABLE in this MODE. This is because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the turbine driven AFW pump.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4 the AFW System may be used for heat removal via the steam generators.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW train when entering MODE 1. There is an increased risk associated with entering MODE 1 with an AFW train inoperable 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 the turbine driven AFW train is inoperable due to one inoperable steam supply in MODE 1, 2, or 3, or if a turbine driven pump is inoperable for any reason while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. For the inoperability of the turbine driven AFW pump due to one inoperable steam supply in MODE 1, 2, or 3, the 7 day Completion Time is reasonable since there is a redundant steam supply line for the turbine driven pump and the turbine driven train is still capable of performing its specified function.

BASES

ACTIONS (continued)

b. For the inoperability of a turbine driven AFW pump while in MODE 3 immediately subsequent to a refueling, the 7 day Completion Time is reasonable due to the minimal decay heat levels in this situation.

c. For both the inoperability of the turbine driven pump due to one inoperable steam supply and an inoperable turbine driven AFW pump while in MODE 3 immediately following a refueling outage, the 7 day Completion Time is reasonable due to the availability of redundant OPERABLE motor driven AFW pumps, and due to the low probability of an event requiring the use of the turbine driven AFW pump.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

Condition A is modified by a Note which limits the applicability of the Condition for an inoperable turbine driven AFW pump in MODE 3 to when the unit has not entered MODE 2 following a refueling. Condition A allows one AFW train to be inoperable for 7 days vice the 72 hour Completion Time in Condition B. This longer Completion Time is based on the reduced decay heat following refueling and prior to the reactor being critical.

B.1 and B.2

With one of the required AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to realign OPERABLE AFW pumps to separate train supply headers within 2 hours (if both train supply headers are OPERABLE) and to restore the AFW train to OPERABLE status within 72 hours. This Condition includes the loss of two required steam supply lines to the turbine driven AFW pump. Required Action B.1 to realign the OPERABLE pumps to separate supply headers preserves train separation and enhances system reliability. The two hours allowed for this Action is reasonable based on operating experience to perform the specified task. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

BASES

ACTIONS (continued)

Required Action B.1 is modified by a Note indicating that the Required Action is only applicable if both supply headers are OPERABLE.

With one inoperable AFW pump, the remaining two AFW pumps will be aligned to separate redundant headers capable of supplying flow to each steam generator.

A realistic analysis of a loss of normal feedwater event demonstrates that one motor driven AFW pump will maintain sufficient steam generator inventory to provide a secondary heat sink and prevent the RCS from exceeding applicable pressure and temperature limits.

For Unit 1, the licensing basis has changed to a requirement for two of three AFW pumps to meet the flow requirements for the limiting DBAs. This change was necessitated by the installation of cavitating venturis in the AFW injection paths. The venturis protect the AFW pumps from runout conditions and allow for flow to be directed to the intact steam generators during a FWLB. Cavitating venturis in each individual injection path to the steam generators ensure that sufficient flow will be delivered to the two intact steam generators during a FWLB. Since no single failures are assumed to occur while in an Action Condition, adequate flow can be supplied by the two OPERABLE AFW pumps. Based on this, the Completion Time of 72 hours for one inoperable AFW pump continues to remain applicable. This change to the Unit 1 licensing basis is consistent with the original licensing basis for Unit 2.

The second Completion Time for Required Action B.2 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

With one of the required motor driven AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3, and the turbine driven AFW train inoperable due to one inoperable steam supply in MODE 1, 2, or 3, action must be taken to restore the affected equipment to OPERABLE status within 24 hours. In this condition, the AFW System may no longer be able to meet the required flow to the SGs assumed in the safety analysis (i.e., from two AFW pumps). Even assuming no further single active

BASES

ACTIONS (continued)

failures when in this Condition, the accident (a FLB or MSLB) could result in the loss of the remaining steam supply to the turbine driven AFW pump. Therefore, only a single OPERABLE AFW pump may be left to mitigate the accident.

The 24 hour Completion Time is reasonable, based on the redundant OPERABLE steam supply to the turbine driven AFW pump, the availability of the remaining OPERABLE motor driven AFW pump, and the low probability of an event occurring that would require the inoperable steam supply to be available for the turbine driven AFW pump.

D.1 and D.2

When Required Action A.1, B.1, B.2, C.1, or C.2 cannot be completed within the required Completion Time, or

- If two AFW trains are inoperable in MODE 1, 2, or 3 for reasons other than Condition C, or

- If one or two feedwater injection headers are inoperable in MODE 1, 2, or 3,

the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 18 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. If a motor driven AFW pump is not available in MODE 4 and the SG(s) are relied on for decay heat removal then Condition F is applicable. However, in MODE 4, two RHR loops may be used for decay heat removal in lieu of the SG(s) consistent with the requirements of LCO 3.4.6, "RCS Loops - MODE 4."

In MODE 4, with one or two feedwater injection headers inoperable, operation is allowed to continue because the remaining OPERABLE injection header(s) provide a flow path to the SG(s) relied on for decay heat removal. Additionally, in MODE 4, the RHR loops may be used in lieu of or to supplement the SG(s) for decay heat removal consistent with the requirements of LCO 3.4.6, "RCS Loops - MODE 4."

BASES

ACTIONS (continued)

E.1

If all three AFW trains or if all three feedwater injection headers are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be subjected to a reduction in MODE that could increase the likelihood of the AFW System being required to support heat removal. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status with the capability of providing flow to the steam generator(s).

Required Action E.1 is modified by a Note indicating that all required MODE changes are suspended until one AFW train is restored to OPERABLE status with the capability of providing flow to the steam generator(s). In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

F.1

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops - MODE 4." With one required AFW train or with the required feedwater injection header(s) inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status with the capability of providing flow to the steam generator(s). The immediate Completion Time is consistent with LCO 3.4.6.

SURVEILLANCE REQUIREMENTS

For the following AFW Surveillance Requirements (SRs), constant communications shall be established and maintained between the control room and the auxiliary feed pump room while any normal AFW pump discharge valve is closed during surveillance testing.

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. Completing verification includes re-verifying these requirements by a second and independent operator. This SR 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 SR also does not apply to valves that cannot

BASES

SURVEILLANCE REQUIREMENTS (continued)

be inadvertently misaligned, such as check valves. This Surveillance 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 SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW System, OPERABILITY (i.e., the intended safety function) continues to be maintained.

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

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. The term "required developed head" refers to the value that is assumed in the AFW safety analysis for developed head at a flow point. This value for required developed head at a flow point is defined as the Minimum Operating Point (MOP) in the Inservice Testing Program. Flow and differential head are normal test parameters of centrifugal pump performance required by the ASME Code (Ref 2). Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this testing is normally performed on recirculation flow. For Unit 1, the recirculation flow rate is assumed to be a fixed value since the recirculation line flow resistance remains constant. For Unit 2, the recirculation flow rate is adjusted to a specific value. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing as required in the ASME Code (Ref. 2) satisfies this requirement.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established for testing the turbine driven AFW pump. This deferral is required because there is insufficient steam pressure to perform the test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by two Notes. Note 1 states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW System, OPERABILITY (i.e., the intended safety function) continues to be maintained. Note 2 indicates the SR is not required to be met in MODE 4 when the steam generator(s) are relied upon for heat removal. In MODE 4, the heat removal requirements are less such that more time is available for operator action to manually initiate AFW if necessary.

SR 3.7.5.4

This SR verifies the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating each AFW pump starts automatically on an actual or simulated actuation signal in MODES 1, 2, and 3. In MODE 4, the required pump's autostart feature is not required. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by three Notes. Note 1 indicates the SR be deferred until suitable test conditions are established for testing the turbine driven AFW pump. This deferral is required because there is insufficient steam pressure to perform the test. Note 2 states that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW System. OPERABILITY (i.e., the intended safety function) continues to be maintained. Note 3 indicates the SR is not required to be met in MODE 4 when steam generator(s) are relied upon for heat removal. In MODE 4, the heat removal requirements are less such that more time is available for operator action to manually initiate AFW if necessary.

SR 3.7.5.5

This SR verifies the AFW is properly aligned by verifying the flow paths from the PPDWST (WT-TK-10 (Unit 1) and 2FWE-TK210 (Unit 2)) to each steam generator prior to entering MODE 2 after more than 30 cumulative days in any combination of MODE 5 or 6 or defueled. OPERABILITY of AFW flow paths must be verified before sufficient core heat is generated that would require the operation of the AFW System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgement and other administrative controls that ensure flow paths remain OPERABLE. To further ensure AFW System alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures the flow path from the PPDWST to the steam generators is properly aligned.

REFERENCES

1. UFSAR, Section 10.3.5.2.2 (Unit 1) and Section 10.4.9 (Unit 2).

2. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.6 Primary Plant Demineralized Water Storage Tank (PPDWST)

BASES

BACKGROUND

The PPDWST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The PPDWST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric dump valves. The AFW pumps operate with recirculation to the PPDWST to ensure a minimum pump flow is maintained.

Because the PPDWST is a principal component in removing residual heat from the RCS, it is designed to withstand earthquakes and other natural phenomena, including missiles that might be generated by natural phenomena. The PPDWST is designed to Seismic Category I to ensure availability of the feedwater supply. Feedwater is also available from alternate sources.

A description of the PPDWST is found in the UFSAR, Section 10.3.5.2.2 (Unit 1) and Section 10.4.9 (Unit 2) (Ref. 1).

APPLICABLE SAFETY ANALYSES

The auxiliary feedwater pumps are normally aligned to take suction from the PPDWST. The PPDWST provides cooling water to remove decay heat and to cool down the unit. Since the Engineered Safety Feature (ESF) design function requires that sufficient feedwater be available during transient and accident conditions to place the unit in a safe shutdown condition, the limiting event for the condensate volume is a loss of offsite power (LOOP) transient. In the event of a LOOP, the PPDWST inventory must be available to maintain the unit in MODE 3 for 9 hours with steam discharge to the atmosphere and with no reactor coolant pumps in operation. The minimum usable volume conservatively bounds the analysis value. The minimum usable volume may be appropriately increased to account for measurement uncertainties.

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

BASES

LCO

The PPDWST level required is equivalent to a usable volume of ≥ 130,000 gallons, which is based on maintaining the unit in MODE 3 for 9 hours with steam discharge to the atmosphere and with no reactor coolant pumps in operation following a LOOP and subsequent reactor trip from full power.

The OPERABILITY of the PPDWST is determined by maintaining the tank level at or above the minimum required level.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the PPDWST is required to be OPERABLE.

In MODE 5 or 6, the PPDWST is not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the PPDWST is not OPERABLE, the OPERABILITY of the backup supply (i.e., river/service water systems) should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup water supply must include verification that the flow paths from the backup water supply to the AFW pumps are OPERABLE. The PPDWST must be restored to OPERABLE status within 7 days, because the backup supply may be performing this function in addition to its normal functions. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. Additionally, verifying the backup water supply every 12 hours is adequate to ensure the backup water supply continues to be available. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the PPDWST.

B.1 and B.2

If the PPDWST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.6.1 This SR verifies the PPDWST contains the required usable volume of cooling water. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 10.3.5.2.2 (Unit 1) and Section 10.4.9 (Unit 2).

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System, which is commonly referred to as the Primary Component Cooling Water System for Unit 2, provides a heat sink for the removal of process and operating heat from components during normal operation. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System, and thus to the environment.

The CCW System consists of two 100% capacity, cooling water trains. Each train shares common piping headers and may be cross-tied during normal operation. The CCW System consists of three 100% capacity pumps, heat exchangers, and associated surge tank (Unit 1 utilizes one surge tank common for both trains). UFSAR, Section 9.4 (Unit 1) and Section 9.2.2.1 (Unit 2) (Ref. 1) lists the required flows for the various equipment cooled by the CCW System. The largest primary CCW heat load occurs during unit cooldown when the Residual Heat Removal (RHR) System is initially placed in operation. With the service water temperature at its maximum limit, two CCW pumps and two CCW heat exchangers can transfer the design heat loads from all components served. During most operating conditions, however, only one CCW pump is necessary to transfer the heat loads. One CCW pump motor is powered from one of the two emergency 4,160 V switchgear buses and a second CCW pump motor is powered from the other bus. The third CCW pump motor, which is not normally connected to either of the buses can be manually connected to either. Additional information on the design and operation of the CCW System, along with a list of the components served, is presented in Reference 1.

APPLICABLE SAFETY ANALYSES

The CCW System serves no Design Basis Accident (DBA) loss of coolant accident (LOCA) mitigation function and is not a system which functions to mitigate the failure of or presents a challenge to the integrity of a fission product barrier. The CCW System has redundant components to ensure performance of the cooling function in the event of a single failure. The principal function of the CCW System is the removal of decay heat from the reactor via the RHR System. The RHR System does not perform a DBA mitigation function. The CCW System is not required in short term accident scenarios to provide cooling water to mitigate the consequences of DBAs. The CCW System, however, is used to supply the RHR heat exchangers, in long term DBA scenarios, with cooling water to cool the unit from RHR entry conditions to Cold Shutdown. The time required for cooldown is a function of the number of CCW and RHR trains operating,

BASES

APPLICABLE SAFETY ANALYSES (continued)

the auxiliary CCW System heat loads (other than RHR), and the service water temperature. The CCW System has been identified in the probabilistic safety assessment as significant to public health and safety.

The CCW System satisfies Criterion 4 of 10 CFR 50.36 (c) (2) (ii).

LCO

The CCW trains are independent of each other to the degree that each has separate controls and power supplies. Should the need arise to cooldown the unit, two trains of CCW must be OPERABLE. At least one CCW train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

A CCW train is considered OPERABLE when:

a. The pump and associated surge tank are OPERABLE and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the required function are OPERABLE.

Each CCW train is considered OPERABLE if it is operating or if it can be placed in service manually.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system. In MODE 4, the CCW System must be prepared to perform its Reactor Coolant System heat removal function, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," be entered if an inoperable CCW train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one CCW train is inoperable, action must be taken to restore it to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train.

BASES

ACTIONS (continued)

B.1 and B.2

If the CCW train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1

Condition C applies to two inoperable CCW trains. Condition C is modified by a Note that states the Condition is only applicable in MODE 4 with inadequate CCW flow to the RHR heat exchangers to support the required decay heat removal needed to maintain the unit in MODE 5. In addition, the Actions are modified by a Note that states LCO 3.0.3 and all other LCO Actions requiring a MODE change from MODE 4 to MODE 5 are suspended until adequate CCW flow to the RHR heat exchangers is established to maintain the unit in MODE 5.

With two inoperable CCW trains, LCO 3.0.3 would be applicable in MODES 1, 2, and 3 and result in the plant being placed in MODE 4. However, without adequate RHR decay heat removal capability, transitioning to MODE 5 from MODE 4 in accordance with LCO 3.0.3 may not be possible. In this case, Condition C would be applicable in MODE 4 and would replace LCO 3.0.3 for two inoperable CCW trains. Condition C provides more appropriate Actions than LCO 3.0.3 for reaching MODE 5 when the required RHR cooling capacity is not available. If adequate RHR decay heat removal capability is available to transition from MODE 4 to MODE 5, Condition C would not be applicable and the requirements of LCO 3.0.3 would be applied until the plant reached MODE 5.

With two CCW trains inoperable and inadequate CCW flow to the RHR heat exchangers to support the required decay heat removal function, action must be initiated immediately to restore one CCW train to OPERABLE status. The action and Completion Time are reasonable, considering the required decay heat removal capacity to maintain the unit in MODE 5 is not available and the other systems available in MODE 4 to safely remove decay heat until adequate cooling capacity is restored to place and maintain the unit in MODE 5.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path to the RHR heat exchangers provides assurance the proper flow paths exist for CCW 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. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance 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. UFSAR, Section 9.4 (Unit 1) and Section 9.2.2.1 (Unit 2).

B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water System (SWS)

BASES

BACKGROUND

The SWS, which is commonly referred to as the Reactor Plant River Water System for Unit 1, provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SWS consists of two 100% capacity, safety related, cooling water trains. There are three 100% capacity main SWS pumps capable of taking suction from the Ohio River at the intake structure supplying the two trains. For Unit 1, one SWS pump is normally operated to supply the quantity of water needed for the essential cooling requirements for all operating conditions. For Unit 2, two SWS pumps are normally operated concurrently to supply the quantity of water needed for the essential cooling requirements for all operating conditions. One SWS pump motor is powered from one of the two emergency 4,160 V switchgear buses and a second SWS pump motor is powered from the other bus. The third SWS pump motor, which is not normally connected to either of the buses can be manually connected to either. The SWS provides cooling water to such loads as the Diesel Generator Cooling System heat exchangers, the Recirculation Spray System heat exchangers, control room emergency cooling coils, charging pump lube oil coolers, and component cooling water heat exchangers. In addition, the SWS provides a source of emergency makeup water to the Auxiliary Feedwater System. Only one of three SWS pumps is needed to provide the cooling for the minimum number of components required for safe shutdown following a DBA. In the event of a DBA or transient, initiating a containment isolation phase B signal, the SWS is designed to supply sufficient cooling water to safely shutdown the unit, assuming any single active component failure coincident with a loss of offsite power (LOOP).

Additional information about the design and operation of the SWS, along with a list of the components served, is presented in the UFSAR, Section 9.9 (Unit 1) and Section 9.2.1 (Unit 2) (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the SWS is for one SWS train to provide cooling to safety related components, required for safe shutdown, following a DBA. These components are listed in Reference 1. The SWS is designed to perform its function with a single failure of any active component, assuming a LOOP. The SWS, in conjunction with the Component

BASES

APPLICABLE SAFETY ANALYSES (continued)

Cooling Water (CCW) System, also cools the unit from residual heat removal (RHR) entry conditions to Cold Shutdown during normal and post accident operations (Reference 2). The time required for this evolution is a function of the number of CCW and RHR System trains that are operating.

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

LCO

Two SWS trains are required to be OPERABLE to provide the required redundancy to ensure 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 SWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. The pump is OPERABLE and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

ACTIONS

A.1

If one SWS train is inoperable, action must be taken to restore it to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SWS train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SWS train could result in loss of SWS function. Required Action A.1 is modified by two Notes. The first Note indicates the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," should be entered if an inoperable SWS train results in an inoperable emergency diesel generator. The second Note indicates the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," should be entered if an inoperable SWS train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. The

BASES

ACTIONS (continued)

72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

B.1 and B.2

If the SWS train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1

Condition C applies to two inoperable SWS trains. Condition C is modified by a Note that states the Condition is only applicable in MODE 4 with inadequate SWS flow to the CCW heat exchangers to support the required decay heat removal needed to maintain the unit in MODE 5. In addition, the Actions are modified by a Note that states LCO 3.0.3 and all other LCO Actions requiring a MODE change from MODE 4 to MODE 5 are suspended until adequate SWS flow to the CCW heat exchangers is established to maintain the unit in MODE 5.

With two inoperable SWS trains, LCO 3.0.3 would be applicable in MODES 1, 2, and 3 and result in the plant being placed in MODE 4. However, without adequate RHR decay heat removal capability, transitioning to MODE 5 from MODE 4 in accordance with LCO 3.0.3 may not be possible. In this case, Condition C would be applicable in MODE 4 and would replace LCO 3.0.3 for two inoperable SWS trains. Condition C provides a more appropriate Action than LCO 3.0.3 for reaching MODE 5 when the required RHR cooling capacity is not available. If adequate RHR decay heat removal capability is available to transition from MODE 4 to MODE 5, Condition C would not be applicable and the requirements of LCO 3.0.3 would be applied until the plant reached MODE 5.

With two SWS trains inoperable and inadequate SWS flow to the CCW heat exchangers to support the required decay heat removal function by the RHR System, action must be initiated immediately to restore one SWS train to OPERABLE status. The action and Completion Time are reasonable, considering the required decay heat removal capacity to maintain the unit in MODE 5 is not available and the other systems available in MODE 4 to safely remove decay heat until adequate cooling capacity is restored to place and maintain the unit in MODE 5.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the SWS components or systems may render those components inoperable, but does not affect the OPERABILITY of the SWS.

Verifying the correct alignment for manual, power operated, and automatic valves in the SWS flow path provides assurance that the proper flow paths exist for SWS operation. This SR 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 being locked, sealed, or secured. 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 3.7.8.2

This SR verifies proper automatic operation of the SWS valves on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.3

This SR verifies proper automatic operation of the SWS pumps on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.9 (Unit 1) and Section 9.2.1 (Unit 2).

2. UFSAR, Section 9.3 (Unit 1) and Section 5.4.7 (Unit 2).

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Service Water System (SWS), which is commonly referred to as the Reactor Plant River Water System for Unit 1. SWS, as used throughout this Bases, applies to both the Unit 2 SWS and the Unit 1 Reactor Plant River Water System.

The UHS for BVPS is the Ohio River as discussed in UFSAR, Section 9.9 (Unit 1) and Section 9.2.5 (Unit 2) (Ref. 1). The two principal functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

The UHS and the SWS have interfaces at the SWS intake structure and the outfall structure. The SWS inlet water temperature is unaffected by the SWS heat loads, because the outfall structure is located sufficiently downstream of the intake structures to prevent recirculation. Therefore, SWS temperatures (at the intake structure or inlet header piping) can be used to verify the required UHS temperature. The basic performance requirements are that a 30 day supply of water be available, and that the design basis temperatures of safety related equipment not be exceeded.

Additional information on the design and operation of the system, along with a list of components served, can be found in Reference 1.

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation.

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis, which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case single active failure (e.g., single failure of a manmade structure). The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 2), as addressed in the UFSAR, which requires a 30 day supply of cooling water in the UHS.

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

BASES

LCO

The UHS is required to be OPERABLE and is considered OPERABLE if it is capable of providing a sufficient volume of water at or below the maximum temperature that would allow the SWS to operate for at least 30 days following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the average UHS temperature should not exceed 90°F (Unit 1) and 89°F (Unit 2) and the level should not fall below 654 ft mean sea level at the intake structure during normal unit operation.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

ACTIONS

A.1 and A.2

If either the UHS temperature or level requirements are not met, the UHS is inoperable and the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR verifies adequate long term (30 day) cooling can be maintained. The specified level also ensures sufficient NPSH is available to operate the SWS pumps. This SR verifies the UHS water level is ≥ 654 ft mean sea level at the intake structure. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.2

This SR verifies the SWS is available to cool the required loads during maximum accident or normal design heat loads for 30 days following a Design Basis Accident. This SR verifies the average water temperature

BASES

SURVEILLANCE REQUIREMENTS (continued)

of the UHS is ≤ 90°F (Unit 1) and ≤ 89°F (Unit 2). The UHS temperature can be determined from SWS temperature indicators at the intake structure or on inlet piping headers. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.9 (Unit 1) and Section 9.2.5 (Unit 2).

2. Regulatory Guide 1.27 (Unit 2) and Safety Guide 27 (Unit 1).

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Ventilation System (CREVS)

BASES

BACKGROUND

The Control Room Emergency Ventilation System (CREVS) provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity.

BVPS has a common control room envelope (CRE) for Unit 1 and Unit 2. The CREVS consists of pressurization fan subsystems, the CRE isolation subsystems, and a CRE boundary that limits the inleakage of unfiltered air.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit 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.

There are three CREVS pressurization fan subsystems, one (Unit 1) and two (Unit 2). The pressurization fan subsystems draw filtered outside air into the CRE.

The CRE isolation subsystems isolate the Unit 1 and Unit 2 normal air intake and exhaust penetration flow paths by closing at least one of the two series isolation dampers in each of the four penetration flow paths. Closure of both units' intake and exhaust isolation dampers may be initiated by an isolation signal from either unit. However, the operation of the intake and exhaust dampers at each unit is dependent upon the availability of that unit's power sources. The isolation subsystem of a CREVS train consists of all 4 isolation dampers in that train (2 per unit). Both the Unit 1 and Unit 2 isolation dampers associated with a train are required OPERABLE for an OPERABLE CREVS train. The isolation subsystem is OPERABLE for a unit when the associated Unit 1 and Unit 2 dampers are capable of closing on that unit's required isolation signals or the damper(s) are secured closed.

BASES

BACKGROUND (continued)

The CREVS pressurization fan subsystem located on the Unit 1 side of the combined control room consists of one manually started pressurization fan and filter subsystem that provides filtered air to pressurize the CRE. The Unit 1 pressurization fan subsystem filter consists of a prefilter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), a high efficiency particulate air (HEPA) filter, and one of the two 100% capacity Unit 1 fans. Only one of the two Unit 1 fans is required for an OPERABLE CREVS train.

The CREVS pressurization fan subsystems located on the Unit 2 side of the CRE consists of two automatically started redundant train related subsystems that draw in outside air through filters to provide filtered air to pressurize the CRE. Each pressurization fan subsystem filter consists of a moisture separator, a HEPA filter, an activated charcoal adsorber, a second HEPA filter, and a fan. A second bank of HEPA filters follows the adsorber section to collect carbon fines and provide backup in case of failure of the main HEPA filter.

For both units, ductwork, heaters, valves or dampers, and instrumentation also form part of the system.

Unit 1 can credit any two of the three available CREVS pressurization fan subsystems to meet the LCO requirement for two OPERABLE CREVS trains. However, Unit 2 can only credit the Unit 2 specific pressurization fan subsystems to meet the LCO requirement for two OPERABLE CREVS trains.

The CREVS is an emergency system, parts of which may also operate during normal unit operations in the standby mode of operation. Upon receipt of a CREVS actuating signal(s), normal unfiltered outside air supply and exhaust dampers to the CRE are closed and (for Unit 2 only) a pressurization fan subsystem is initiated and the emergency air supply damper in the operating CREVS train is opened to bring in outside air through filters to pressurize the CRE. The Unit 1 pressurization fan subsystem is manually placed in service if required. The air continues to be recirculated within the CRE by the Control Room Emergency Air Cooling System (CREACS) (LCO 3.7.11) both during normal operation and during CREVS operation.

Pressurization of the CRE minimizes infiltration of unfiltered air through the CRE boundary from all the surrounding areas adjacent to the CRE boundary. A single CREVS train operating at a flow rate of 800 to 1000 cfm will pressurize the CRE to maintain a positive pressure relative to the outside atmosphere. The CREVS operation in maintaining the CRE habitable is discussed in UFSAR, Section 9.13 (Unit 1) and Section 9.4 (Unit 2) (Ref. 1).

BASES

BACKGROUND (continued)

Redundant CREVS trains are required OPERABLE to ensure the pressurization and filtration function can be accomplished should one train fail. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. The CREVS is designed in accordance with Seismic Category I requirements.

The CREVS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding 5 rem total effective dose equivalent (TEDE). This limitation is consistent with the requirements of General Design Criteria 19 of Appendix "A", 10 CFR 50 and 10 CFR 50.67.

The CREVS is automatically actuated by a containment isolation phase B (CIB) signal or a control room area high radiation signal. In addition, the CREVS can be actuated manually. The OPERABILITY requirements for the CREVS instrumentation are specified in LCO 3.3.7, "CREVS Actuation Instrumentation."

CREVS does not have automatic detection and isolation for hazardous chemicals or smoke. Refer to Applicable Safety Analyses for a discussion of the design basis of CREVS with regard to these events.

APPLICABLE SAFETY ANALYSES

The CREVS components are arranged in redundant, safety related ventilation trains. The location of most components and ducting within the CRE helps to minimize air in leakage and ensures an adequate supply of filtered air to all areas requiring access. The CREVS provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE habitability analyses for the most limiting DBAs: loss of coolant accident (LOCA), control rod ejection accident (CREA), and main steam line break (MSLB) accident, presented in the UFSAR, Chapter 14 (Unit 1) and Chapter 15 (Unit 2) (Ref. 2). CRE isolation and operation of CREVS was not credited in other DBAs.

The worst case single active failure of a component of the CREVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The LOCA accident analysis assumes an automatic isolation of the CRE normal ventilation system following a CIB signal and subsequent manual initiation of a CREVS pressurization fan subsystem for filtered makeup and pressurization of the CRE. Although the CIB signal will automatically start one of the two Unit 2 CREVS pressurization fan subsystems, a

BASES

APPLICABLE SAFETY ANALYSES (continued)

30 minute delay to allow for manual initiation of a CREVS pressurization fan subsystem is specifically assumed in the analysis to permit the use of the Unit 1 CREVS pressurization fan subsystem which requires manual operator action to place in service (Ref. 3). The CREA and the MSLB accident analyses assume manual initiation of the emergency pressurization mode of operation of CRE ventilation (i.e., CRE ventilation isolation, filtered makeup and pressurization), within 30 minutes after the accident.

Although the CRE occupant dose calculations for the limiting DBAs (i.e., LOCA, CREA, and MSLB) assume that the CRE is pressurized in 30 minutes of the accident by manually actuating a pressurization fan subsystem, the specification conservatively requires automatic actuation of a Unit 2 CREVS pressurization fan subsystem.

The current safety analyses do not assume the control room area radiation monitors provide a CREVS actuation signal for any DBA. However, requirements for the automatic initiation of CREVS (both isolation and pressurization fan subsystems) on high radiation are retained in the Technical Specifications in case this automatic function is required to support the assumptions of a fuel handling accident analysis for the movement of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) or the movement of fuel over recently irradiated fuel consistent with the guidance of NUREG-1431 (Ref. 4).

An automatic start time delay is included in the initiation circuitry of the Unit 2 CREVS pressurization fan subsystems. The basis for this time delay includes the following considerations:

1. The delay times prevent loading of the pressurization fans onto the emergency busses until after the emergency diesel generator load sequencing is completed.

2. The pressurization fan delay times are staggered to ensure only one fan will be operating.

3. A pressurization fan is started early to minimize dose to the operators.

4. The delay times are selected such that sufficient time will be available for the manual initiation of a pressurization fan subsystem within 30 minutes after an accident should a pressurization fan fail to start.

BASES

APPLICABLE SAFETY ANALYSES (continued)

An evaluation of all chemical hazards from onsite, offsite, and transportation sources has determined that the probability of a hazardous chemical spill resulting in unacceptable exposures was less than NRC design basis criteria. As a result, the plant design basis as described in BVPS Unit 2 UFSAR, Section 2.2.3.1.2 and 6.4.4.2 (Ref. 5) does not postulate any hazardous chemical release events. Therefore, physical provisions for protection against hazardous chemicals are not required and CRE inleakage of hazardous chemicals would be limited by the inleakage rate established for radiological events. If a hazardous chemical release were identified to be onsite, the CRE would be manually isolated to minimize CRE inleakage as a defense in depth measure, by closing all supply and exhaust dampers and verifying that CREVS is not in operation. Technical Specification Amendment No. 233 (Unit 1) and No. 115 (Unit 2) (Ref. 6) removed the control room chlorine detection system. In addition, Amendment No. 257 (Unit 1) and No. 139 (Unit 2) (Ref. 7) which removed the bottled air pressurization system, confirmed that the ability to manually isolate the CRE is sufficient to justify removal of these systems with respect to hazardous chemical events.

In the event of a fire outside the control room, the CRE would be manually isolated to minimize CRE inleakage. If the ability of CRE occupants to remain in the control room is compromised, then remote shutdown locations are available. Therefore, no quantitative limits for CRE inleakage of smoke have been established. Technical Specification Amendment No. 257 (Unit 1) and No. 139 (Unit 2) (Ref. 7) which removed the bottled air pressurization system, confirmed that the ability to manually isolate the CRE in combination with availability of self-contained breathing apparatus is sufficient to justify removal of the system with respect to a smoke event. Therefore, a smoke challenge 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.

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

LCO

Two CREVS trains including the associated train related inlet and exhaust isolation dampers are required to be OPERABLE to ensure that at least one train is available if a single active failure disables the other train. A combination of two out of three CREVS pressurization fan subsystems from either Unit 1 or Unit 2 satisfies the LCO requirement for Unit 1. Only the Unit 2 CREVS pressurization fan subsystems may be used to satisfy the LCO requirement for Unit 2.

BASES

LCO (continued)

The OPERABILITY of CREVS ensures that the CRE will remain habitable with respect to potential radiation hazards for operations personnel during and following all credible accident conditions. The OPERABILITY of this system is based on limiting the radiation exposure to personnel occupying the CRE to 5 rem TEDE. This limitation is consistent with the requirements of General Design Criteria 19 of Appendix "A", 10 CFR 50 and 10 CFR 50.67. Total system failure, such as from a loss of all ventilation trains or from an inoperable CRE boundary, could result in exceeding these dose limits in the event of a large radioactive release.

Each CREVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A CREVS train is OPERABLE when the associated:

a. Fan is OPERABLE (including required automatic start capability for Unit 2 fans),

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions, and

c. Heater, prefilter (Unit 1), moisture separator (Unit 2), ductwork, valves, and dampers are OPERABLE (i.e., capable of supporting pressurization of the CRE when a CREVS train is actuated). This includes:

   1) In MODES 1, 2, 3, and 4, the series normal air intake and exhaust isolation dampers for both units must be OPERABLE and capable of automatic closure on a CIB actuation signal. The series normal air intake and exhaust isolation dampers for both units may also be considered OPERABLE when secured in a closed position with power removed.

   2) During fuel assembly movement involving recently irradiated fuel assemblies, the series normal air intake and exhaust isolation dampers for both units must be OPERABLE and capable of automatic initiation by a control room high radiation signal. The series air intake and exhaust isolation dampers for both units may also be considered OPERABLE when secured in a closed position with power removed.

LCO 3.3.7, "CREVS Actuation Instrumentation," contains the OPERABILITY, ACTION, and Surveillance Requirements for the CREVS actuating instrumentation.

BASES

LCO (continued)

In order for the CREVS trains 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 (hatches, access panels, floor plugs, etc.), 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. If the above conditions for utilizing the LCO Note cannot be met, then Action B should be entered.

APPLICABILITY

In MODES 1, 2, 3, 4, and during the movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) and the movement of fuel assemblies over recently irradiated fuel assemblies, the CREVS is required to be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

In MODES 5 and 6, when no fuel movement involving recently irradiated fuel is taking place, there are no requirements for CREVS OPERABILITY consistent with the safety analyses assumptions applicable in these MODES. A fuel handling accident (FHA) involving non-recently irradiated fuel will result in radiation exposure, to personnel occupying the CRE, that is within the guideline values specified in 10 CFR 50.67 without any reliance on the requirements of this Specification to limit personnel exposure.

This LCO is applicable during movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) and during movement of fuel assemblies over recently irradiated fuel assemblies. During fuel movement involving recently irradiated fuel there is a potential for a limiting FHA for which the requirements of this Specification may be necessary to limit radiation exposure to personnel occupying the CRE to within the requirements of

BASES

APPLICABILITY (continued)

10 CFR 50.67. Although the movement of recently irradiated fuel is not currently permitted, these requirements are retained in the Technical Specifications in case the CREVS is necessary to support the assumptions of a safety analysis for fuel movement involving recently irradiated fuel, consistent with the guidance of Reference 4.

ACTIONS

A.1

When one required CREVS train is inoperable for reasons other than an inoperable CRE boundary (this action includes one or more of the associated train related series isolation dampers inoperable), action must be taken to restore it to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREVS train (including the associated train of isolation dampers) is adequate to perform the CRE occupant radiation protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREVS train could result in loss of CREVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time, and the ability of the remaining train to provide the required safety function.

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 TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. As discussed in the Applicable Safety Analyses section, the current licensing basis identifies that CRE inleakage limits for hazardous chemicals and smoke are not necessary to protect CRE occupants; therefore, the limit established for radiological events is the limiting value for determining entry into Condition B for an inoperable CRE boundary. 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 exceed the calculated dose of the licensing basis analyses of DBA consequences, and that the CRE occupants are protected from hazardous chemicals and smoke. These

BASES

ACTIONS (continued)

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 and 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, 3, or 4, if the inoperable CREVS train or the CRE boundary cannot be restored to OPERABLE status within the required Completion Time the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

During fuel movement involving recently irradiated fuel assemblies, if an inoperable CREVS train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE CREVS train must immediately be placed in the emergency pressurization mode of operation. This action requires the CRE ventilation isolation dampers to be closed and the CRE to be pressurized by the operating CREVS train. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

An alternative action is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This involves suspending movement of recently irradiated fuel assemblies and suspending movement of fuel assemblies over recently irradiated fuel assemblies. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

BASES

ACTIONS (continued)

E.1

During fuel movement involving recently irradiated fuel assemblies, if two required CREVS trains are inoperable or with one or more required CREVS trains inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. Two inoperable trains also include the conditions of one or more inoperable series isolation dampers in both trains or one or more inoperable series isolation dampers in one train and the opposite CREVS train inoperable. This Action involves suspending movement of recently irradiated fuel assemblies and suspending movement of fuel assemblies over recently irradiated fuel assemblies. This places the unit in a condition that minimizes the accident risk. This Action does not preclude the movement of fuel to a safe position.

F.1

If both required CREVS trains are inoperable in MODES 1, 2, 3, or 4 for reasons other than an inoperable CRE boundary (i.e., Condition B) the CREVS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Two inoperable trains also include the conditions of one or more inoperable series isolation dampers in both trains or one or more inoperable series isolation dampers in one train and the opposite CREVS train inoperable. In this condition, Specification 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check of this system. The CREVS fan and filter flow path is operated for ≥ 15 minutes by initiating flow through the HEPA filter and charcoal adsorber train with heaters operating to ensure that they function properly. This Surveillance does not require that the CRE be isolated in order to verify fan and filter flow path functionality. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.2

This SR verifies that the required CREVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.3

This SR verifies that each CREVS train operates as required on an actual or simulated containment isolation phase B actuation signal (only required in MODES 1, 2, 3, and 4) and control room high radiation actuation signal (only required for fuel movement involving recently irradiated fuel). The actuation testing includes verification that each train of series air intake and exhaust isolation dampers for both units close to isolate the CRE from the outside atmosphere. In addition, for Unit 2, the automatic start (following a time delay) of each CREVS pressurization fan subsystem supplying air to pressurize the CRE through the HEPA filters and charcoal adsorber banks is verified. For Unit 1, an automatic start of the CREVS pressurization fan subsystem is not required since the Unit 1 subsystem is placed in service by manual operator action.

LCO 3.3.7, "CREVS Actuation Instrumentation," contains the OPERABILITY requirements including the Applicability, ACTION, and Surveillance Requirements for the CREVS actuating instrumentation.

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

SR 3.7.10.4

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 TEDE. 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 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 9.13 (Unit 1) and Sections 6.4 and 9.4 (Unit 2).
2. UFSAR, Section 14 (Unit 1) and Chapter 15 (Unit 2).
3. UFSAR Table 14.1-1A (Unit 1) and UFSAR Table 15.0-13 (Unit 2).
4. NUREG-1431, Rev. 2, Standard Technical Specifications for Westinghouse Plants.
5. UFSAR, Sections 2.2.3.1.2 and 6.4.4.2 (Unit 2).
6. Amendment No. 233 (Unit 1) and Amendment No. 115 (Unit 2), September 7, 2000.
7. Amendment No. 257 (Unit 1) and Amendment No. 139 (Unit 2), September 10, 2003.
8. Regulatory Guide 1.196.
9. NEI 99-03, "Control Room Habitability Assessment," June 2001.
10. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "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).

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Emergency Air Cooling System (CREACS)

BASES

BACKGROUND

The Control Room Emergency Air Cooling System (CREACS) provides 1) a control room heat removal function following isolation of the control room, and 2) control room atmosphere purge capability for the combined units' main control room. The heat removal function ensures that the control equipment qualification is maintained following isolation of the control room. The purge function is necessary to limit the dose received by control room personnel following certain design basis accidents (DBAs). Each unit has its own CREACS. Each unit's CREACS consists of a single ventilation air intake and two independent and redundant trains consisting of river/service water emergency cooling coils, ventilation ducts, fans and fan controls. However, the CREACS trains share common ventilation ductwork and normal air inlet and exhaust flow paths. The CREACS heat removal function is discussed in the UFSAR, Section 9.13 (Unit 1) and Section 9.4 (Unit 2) (Ref. 1). The CREACS control room atmosphere purge function is discussed in the UFSAR, Table 14.1-1A (Unit 1) and Table 15.0-13 (Unit 2) (Ref. 2).

The CREACS is an emergency system, parts of which operate during normal unit operations. A single train of CREACS on each unit is capable of maintaining its side of the combined control room at ≤ the equipment design limit of 120°F. A single train of CREACS from either unit is capable of providing adequate control room atmosphere purge capability to meet either unit's DBA requirements.

APPLICABLE SAFETY ANALYSES

The design basis of the CREACS heat removal function is to provide emergency air cooling for the control room to maintain the temperature within the equipment design limit for a mild environment (120°F) following certain DBAs when the control room is isolated. The CREACS also provides an atmosphere purge function for the control room following certain DBAs. Only manual actuation is credited for both CREACS functions at each unit.

The CREACS components are arranged in redundant, safety related trains. A single active failure of a component of the CREACS, with a loss of offsite power, does not impair the ability of the system to perform its design function. The CREACS is designed in accordance with Seismic Category I requirements.

During normal and emergency control room operation, the control room air cooling is usually maintained by the non safety related air conditioning equipment which is integral to the control room ventilation systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During emergency operation when the control room is isolated, the safety related CREACS is manually initiated to provide air cooling to maintain the temperature ≤ 120°F when the normal non safety related air conditioning becomes unavailable. The CREACS is capable of removing sensible and latent heat loads from the control room, which include consideration of equipment heat loads to ensure equipment OPERABILITY. The CREACS heat removal function is only required following post-DBA isolation of the control room (when control room isolation is required to meet radiological dose analysis requirements) and the normal non safety related air conditioning equipment is unavailable.

The heat removal function of CREACS is credited in DBAs for MODES 1, 2, 3, and 4 (e.g., the loss of coolant accident (LOCA), the main steam line break (MSLB) and control rod ejection DBAs for both units require control room isolation). Since neither unit requires control room isolation (and hence the control room heat function of CREACS) to meet its fuel handling accident (FHA) DBA nor requires control room isolation following any other DBA in MODES 5 and 6 (e.g., waste gas tank rupture DBA), the heat removal function of CREACS is not required in MODES 5 and 6 or during fuel movement involving non-recently irradiated fuel.

The design basis of the CREACS control room ventilation purge function ensures the capability to manually purge the air from the control room for selected DBAs to ensure acceptable dose consequences to the control room personnel following a DBA.

For both Unit 1 and Unit 2, the MSLB and steam generator tube rupture (SGTR) accident analyses credit a manually initiated 30 minute control room ventilation purge at a flow rate of ≥ 16,200 cfm after the accident sequence is complete and the environmental release has been terminated. Also for Unit 1 only, the FHA analysis for fuel movement involving non-recently irradiated fuel credits a manually initiated 30 minute control room ventilation purge at a flow rate of ≥ 16,200 cfm after the accident sequence is complete and the environmental release has been terminated. The dose consequence analyses assume that for the MSLB, the SGTR, and the Unit 1 FHA, control room purge is initiated at T=24 hours, T=8 hours and T=2 hours after accident initiation, respectively.

Only Unit 1 requires the purge function of CREACS during fuel movement involving non-recently irradiated fuel. Therefore, the purge function of CREACS is required for Unit 1 during fuel movement involving non-recently irradiated fuel. Thus, the control room ventilation purge functions of CREACS are credited in DBAs for MODES 1, 2, 3, and 4 at both units, and for fuel movement involving non-recently irradiated fuel assemblies at Unit 1.

BASES

APPLICABLE SAFETY ANALYSES (continued)

This LCO is also applicable for both units during movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) and during movement of fuel assemblies over recently irradiated fuel assemblies. The requirement for recently irradiated fuel assemblies is included because there is a potential for a limiting FHA for which the requirements of this Specification may be necessary to limit radiation exposure to personnel occupying the control room to within the requirements of 10 CFR 50.67. Although the movement of recently irradiated fuel is not currently permitted for either unit, the requirements for both the temperature control and purge functions are retained in the Technical Specifications in case the CREACS functions are necessary to support the assumptions of a safety analysis for fuel movement involving recently irradiated fuel, consistent with the guidance of NUREG-1431 (Ref. 3).

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

LCO

The Unit 1 FHA analysis does not require control room isolation to limit the dose to control room personnel to within the required limits. Therefore, a Note modifying the LCO requirement is included to clarify that the Unit 1 CREACS heat removal function is not required OPERABLE to support fuel movement involving non-recently irradiated fuel. Only the purge function of the Unit 1 CREACS is required to support fuel movement involving non-recently irradiated fuel as only the purge function is required in the Unit 1 accident analysis to limit dose. The Note is only applicable to Unit 1 because operation of the Unit 2 CREACS is not required by the Unit 2 FHA analysis for fuel movement involving non-recently irradiated fuel. Therefore, operation of the Unit 2 CREACS is not required to limit the dose to control room personnel from a FHA involving non-recently irradiated fuel.

Two trains of the CREACS are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other train. Total system failure of the heat removal function could result in the equipment operating temperature exceeding limits in the event of an accident. Total system failure of the control room atmosphere purge function could result in exceeding a dose of 5 rem TEDE to the control room operator in the event of a large radioactive release following a MSLB, SGTR, or a Unit 1 FHA.

BASES

LCO (continued)

With regard to the control room atmospheric purge function only, the LCO requirement for two OPERABLE CREACS trains may be met by crediting OPERABLE Unit 1 train(s) for Unit 2 and crediting OPERABLE Unit 2 train(s) for Unit 1. The control room atmospheric purge flow requirements for each unit are the same and the control room envelope is common. Therefore, the purge flow assumed in the DBA analysis may be accomplished by the manual initiation of a CREACS train from either unit.

The CREACS is considered to be OPERABLE when the individual components necessary to maintain the control room temperature ≤ 120°F (when the control room is isolated) and to provide the control room ventilation purge function at the required flow rate are OPERABLE in two trains. These components include the river/service water emergency cooling coils, necessary ductwork and associated dampers, fans, and associated fan controls. The capability to manually operate the components of the CREACS is all that is required for OPERABILITY. In addition, the CREACS must be OPERABLE to the extent that air circulation necessary for the required temperature control can be maintained.

APPLICABILITY

CREACS must be OPERABLE in MODES 1, 2, 3, and 4 at either unit and during fuel movement involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) at either unit. The CREACS ensures that control room temperatures will not exceed equipment operational requirements and that the control room ventilation is capable of purging the control room atmosphere after a DBA to maintain dose within the limit.

For Unit 1 only, during movement of non-recently irradiated fuel assemblies and during movement of fuel assemblies over non-recently irradiated fuel assemblies, the ventilation purge function of CREACS must be OPERABLE. The Unit 1 temperature control function of CREACS is not required OPERABLE during fuel movement involving non-recently irradiated fuel because the Unit 1 FHA analysis does not require control room isolation to limit dose.

CREACS is not required in MODES 5 or 6 at either unit during no fuel movement nor is it required during fuel movement involving non-recently irradiated fuel movement at Unit 2.

BASES

ACTIONS

A.1

With one CREACS train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CREACS train is adequate to maintain the control room temperature ≤ 120°F when the control room is isolated and provide the required control room atmosphere purge function. However, the overall reliability is reduced because a single failure in the OPERABLE CREACS train could result in loss of CREACS function. The 30 day Completion Time is based on the low probability of an event requiring control room isolation or purge, the consideration that the remaining train can provide the required protection, and that alternate safety or nonsafety related means of cooling the control room air and of purging the control room atmosphere are available.

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable CREACS train cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes the risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1 and C.2

Condition C is modified by two Notes indicating the applicability of this Condition to each unit. Note 1 states that the Condition is only applicable to Unit 1 during movement of irradiated fuel assemblies and fuel assemblies over irradiated fuel assemblies. Note 2 states that this Condition is only applicable to Unit 2 during movement of recently irradiated fuel assemblies and fuel assemblies over recently irradiated fuel assemblies. If the inoperable CREACS train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE CREACS train must be placed in operation immediately. This action requires that the OPERABLE CREACS ventilation fan be in service and circulating control room air, and if the heat removal function is required by the LCO, with river/service water being supplied to the emergency cooling coils. This action ensures the remaining train is OPERABLE and active failures will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room or a purge of the control room atmosphere.

BASES

ACTIONS (continued)

This involves suspending movement of irradiated fuel assemblies and suspending movement of fuel assemblies over irradiated fuel assemblies. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

D.1

Condition D is modified by two Notes indicating the applicability of this Condition to each unit. Note 1 states that the Condition is only applicable to Unit 1 during movement of irradiated fuel assemblies and fuel assemblies over irradiated fuel assemblies. Note 2 states that this Condition is only applicable to Unit 2 during movement of recently irradiated fuel assemblies and fuel assemblies over recently irradiated fuel assemblies. With two CREACS trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the control room or a purge of the control room atmosphere. This involves suspending movement of irradiated fuel assemblies and suspending movement of fuel assemblies over irradiated fuel assemblies. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1

If both CREACS trains are inoperable in MODE 1, 2, 3, or 4, the control room CREACS may not be capable of performing its intended function. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies the heat removal capability of the system is sufficient to remove the required heat load to maintain the control room temperature within the equipment design limit (≤ 120°F). The verification of the CREACS heat removal capability consists of a combination of river/service water flow measurement, fan performance, and mechanical cleaning and inspections of the river/service water cooling coils.

This SR also verifies the control room atmosphere purge capability of the system is sufficient to remove air from the control room for the DBAs that require a control room purge to limit dose. The control room purge capability is verified by assuring each train of CREACS can be aligned to purge the control room atmosphere and can achieve the required purge flow rate of ≥ 16,200 cfm. This part of the SR may be accomplished by

BASES

SURVEILLANCE REQUIREMENTS (continued)

measuring fan performance during normal system alignment to verify the fan's capability to purge the control room at the required flow rate. The ability of the required dampers to be aligned for a control room purge can be verified by observing partial movement of the dampers. Realignment of the CREACS to the purge mode of operation and measuring the actual purge flow rate is not required to satisfy this SR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.13 (Unit 1) and Section 9.4 (Unit 2).
2. UFSAR, Table 14.1-1A (Unit 1) and Table 15.0-13 (Unit 2).
3. NUREG-1431, Rev. 2, Standard Technical Specifications for Westinghouse Plants.

B 3.7 PLANT SYSTEMS

B 3.7.12 Supplemental Leak Collection and Release System (SLCRS)

BASES

BACKGROUND

SLCRS filters airborne radioactivity from the containment building (Unit 1 only) and the fuel building (both Units) following a fuel handling accident involving recently irradiated fuel. This ensures that, prior to release to the environment, the exhaust from these areas in the event of a fuel handling accident is limited to radioactive releases within 10 CFR 50.67 (Ref. 1) limits. For Unit 1, the SLCRS train consists of a prefilter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), a high efficiency particulate air (HEPA) filter, and a filter exhaust fan. Ductwork, valves or dampers, and instrumentation also form part of the system. For Unit 2, the SLCRS train consists of a heater, a demister, a HEPA filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a filter exhaust fan. Ductwork, valves or dampers, and instrumentation also form part of the system, as well as demisters functioning to reduce the relative humidity of the air stream. For Unit 2 only, a second bank of HEPA filters follows the adsorber section to collect carbon fines and provides a backup in case the main HEPA filter bank fails. The downstream HEPA filter is not credited in the accident analysis, but serves to collect charcoal fines, and to back up the upstream HEPA filter should it develop a leak.

The SLCRS is discussed in References 2 and 3. The SLCRS may be used for normal, as well as post accident, atmospheric cleanup functions. During normal operation, the SLCRS provides ventilation to the areas it serves.

APPLICABLE SAFETY ANALYSES

During fuel handling operations, the postulated event that results in the most severe radiological consequences is a fuel handling accident (Ref. 4). The limiting fuel handling accident analyzed in Reference 4, includes dropping a single irradiated fuel assembly and handling tool (conservatively estimated at 2500 pounds) directly onto another irradiated fuel assembly resulting in both assemblies being damaged. The analysis assumes a 100 hour decay time prior to moving irradiated fuel.

The applicable limits for offsite and control room dose from a fuel handling accident are specified in 10 CFR 50.67. Standard Review Plan, Section 15.0.1, Rev 0 (Ref. 5) provides an additional offsite dose criteria of 6.3 rem total effective dose equivalent (TEDE) for fuel handling accidents.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The water level requirements of LCO 3.7.15, "Fuel Storage Pool Water Level," in conjunction with a minimum decay time of 100 hours prior to irradiated fuel movement, ensure the resulting offsite and control room dose from the limiting fuel handling accident is within the limits required by 10 CFR 50.67 and within the acceptance criteria of Reference 5 without the need for containment and fuel building closure or filtration. Therefore, the SLCRS requirements contained in LCO 3.7.12 are only applicable during refueling operations involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). Current requirements based on the decay time of the fuel prevent the movement of recently irradiated fuel. However, the requirements for SLCRS are retained in the Technical Specifications in case these requirements are necessary to support fuel movement involving recently irradiated fuel consistent with the guidance of NUREG-1431 (Ref. 6).

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

LCO

This LCO limits the consequences of a fuel handling accident involving recently irradiated fuel in the containment (Unit 1 only) and the fuel storage pool (both units) by limiting the potential escape paths for fission product radioactivity. One train of the SLCRS exhausting from the fuel building and/or for Unit 1, the containment is required to be OPERABLE and in operation during fuel movement involving recently irradiated fuel with the required area exhaust flow discharging through the SLCRS HEPA filters and charcoal adsorbers. This ensures that air, prior to release to the environment, is being filtered during fuel movement within the fuel storage pool and/or, for Unit 1 only, during fuel movement within the containment when required in accordance with LCO 3.9.3.c.3. System failure could result in the atmospheric release from SLCRS exceeding 10 CFR 50.67 limits in the event of a fuel handling accident involving recently irradiated fuel. The SLCRS is considered OPERABLE when individual components ensure the radioactivity released in the areas of the containment (Unit 1 only) and the fuel building is filtered through the SLCRS and that fuel building doors are closed.

A SLCRS train is considered OPERABLE when its associated:

a. Fan is OPERABLE,

b. HEPA filter and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions, and

c. Heater (Unit 2 only), demister (Unit 2 only), ductwork, valves, and dampers are OPERABLE and air flow can be maintained.

BASES

LCO (continued)

The SLCRS is considered in operation whenever the required area(s) exhaust flow is discharging through at least one train of the SLCRS HEPA filters and charcoal adsorbers. The LCO is modified by a Note allowing the fuel building boundary to be opened intermittently under administrative controls. 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 consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when fuel building isolation is required to support SLCRS operation.

As clarified in the LCO 3.7.14 NOTE, applicable to Unit 2 only, Specification 3.7.12 applies to the fuel cask area when a fuel assembly is in the cask area during the installation phase of the Unit 2 rerack project.

APPLICABILITY

When required in accordance with LCO 3.9.3.c.3 (for Unit 1), one train of SLCRS is required to be OPERABLE and in operation to alleviate the consequences of a fuel handling accident inside containment. This Applicability applies only to Unit 1 in accordance with the provisions of LCO 3.9.3, "Containment Penetrations" when the Containment Purge and Exhaust System penetrations are open coincident with fuel movement involving recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) within containment.

During movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) within the fuel storage pool or during movement of fuel assemblies over recently irradiated fuel assemblies within the fuel storage pool, one train of SLCRS is required to be OPERABLE and in operation to alleviate the consequences of a potential fuel handling accident.

Since SLCRS is not credited in any existing DBA analysis applicable in MODES 1, 2, 3, 4, 5, and 6 the SLCRS is not required to be OPERABLE in these MODES (except as required to support fuel movement involving recently irradiated fuel assemblies described above).

ACTIONS

A.1

A Note modifies Condition A since this Condition is only applicable to Unit 1. Only Unit 1 relies on SLCRS to filter the exhaust from the containment building to mitigate a fuel handling accident involving the movement of recently irradiated fuel.

BASES

ACTIONS (continued)

This Condition is only applicable when a Unit 1 SLCRS train is required OPERABLE and in operation in accordance with the provision of the containment penetrations LCO requirement 3.9.3.c.3. If the required SLCRS train is inoperable or not in operation, the requirements of LCO 3.9.3 are not met. Immediate action must be taken to place the unit in a condition in which LCO 3.9.3 does not apply. The applicable Conditions and Required Actions of LCO 3.9.3, "Containment Penetrations" must be entered immediately. The Required Actions of LCO 3.9.3 provide the appropriate precautions, for this condition, to preclude a fuel handling accident involving recently irradiated fuel inside containment for which the SLCRS train is required.

B.1 and B.2

A Note indicating that LCO 3.0.3 does not apply modifies Required Action B.1 and B.2.

With SLCRS inoperable or not in operation the requirements of the LCO cannot be met during fuel movement involving recently irradiated fuel within the fuel storage pool. Immediate action must be taken to place the unit in a condition in which the LCO does not apply. Immediate action must be taken to suspend movement of recently irradiated fuel assemblies and the movement of fuel assemblies over recently irradiated fuel assemblies in the fuel storage pool. This will preclude a fuel handling accident involving recently irradiated fuel. The requirements of this action do not preclude the movement of fuel assemblies to a safe position.

If fuel movement involving recently irradiated fuel takes place in MODES 1, 2, 3, or 4, LCO 3.0.3 is applicable. However, fuel movement is independent of reactor operation. Therefore, a plant shutdown in accordance with LCO 3.0.3 is not required if this Required Action is not met.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

This SR requires verification that the required portion (fuel building exhaust or containment exhaust (Unit 1)) of the SLCRS train is in operation with the required area exhaust flow discharging through the SLCRS HEPA filters and charcoal adsorbers. Verification includes operation of fans, alignment of dampers, and discharge flow paths from the fuel building or containment (Unit 1 only). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.2

This SR verifies that the required SLCRS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorbers 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 3.7.12.3

This SR verifies the integrity of the fuel building enclosure. The ability of the fuel building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the SLCRS. During fuel movement involving recently irradiated fuel assemblies in the fuel storage pool, the SLCRS must be OPERABLE and in operation. To ensure performance during a fuel handling accident the fuel pool storage area must be maintained at a negative pressure relative to atmospheric pressure during system operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A Note that states this Surveillance is only required to be met during fuel movement involving recently irradiated fuel assemblies within the fuel storage pool modifies this SR. This Note is necessary as the Unit 1 SLCRS is also required in accordance with LCO 3.9.3.c.3 during fuel movement involving recently irradiated fuel inside containment. As SR 3.7.12.3 has nothing to do with fuel movement inside containment, it is not required in order to confirm the OPERABILITY of a Unit 1 SLCRS train for compliance with LCO 3.9.3.c.3.

REFERENCES

1. 10 CFR 50.67.
2. UFSAR, Section 6.6 (Unit 1) and Section 6.5.3.2 (Unit 2).
3. UFSAR, Section 9.13.2 (Unit 1) and Section 9.4 (Unit 2).
4. UFSAR Section 14.2.1 (Unit 1) and Section 15.7.4 (Unit 2).
5. NUREG-0800, Section 15.0.1, Rev 0.

BASES

REFERENCES (continued)

6. NUREG-1431, Rev. 2, Standard Technical Specifications for Westinghouse Plants.

B 3.7 PLANT SYSTEMS

B 3.7.13 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 150 gallons per day steam generator tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 0.35 μCi/gm DOSE EQUIVALENT I-131 (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE.

Operating a unit at the allowable primary and secondary coolant specific activity limits will result in exposures within the 10 CFR 50.67 (Ref. 1) total effective dose equivalent (TEDE) limits, as supplemented by Regulatory Guide 1.183 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the UFSAR, Chapter 14 (Unit 1) and Chapter 15 (Unit 2) (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed the 10 CFR 50.67 (Ref. 1) TEDE limits, as supplemented by Regulatory Guide 1.183 (Ref. 3).

The MSLB accident analysis assumes a total release of iodine activity in the steam generator connected to the failed steam line. In addition, a portion of the iodine activity in the remaining steam generators is also released via the steaming process due to assumption of loss of offsite

BASES

APPLICABLE SAFETY ANALYSES (continued)

power. With the loss of offsite power, the remaining steam generators are utilized for core decay heat removal by venting steam to the atmosphere through the MSSVs and steam generator atmospheric dump valves (ADVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the MSSVs and ADVs during the event. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be $\leq$ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to within the required limits (Ref. 1 and Ref. 3).

Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

BASES

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity is not within limits, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.67.
2. UFSAR, Chapter 14 (Unit 1) and Chapter 15 (Unit 2).
3. Regulatory Guide 1.183, July 2000.

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pool Storage

BASES

BACKGROUND

The spent fuel storage racks contain storage locations for 1627 fuel assemblies (Unit 1) and 1088 fuel assemblies when the spent fuel storage pool contains only Boraflex racks or 1690 fuel assemblies when the spent fuel storage pool contains only Metamic racks (Unit 2). The racks are designed to store Westinghouse 17X17 fuel assemblies with nominal enrichment up to 5.0 weight percent.

For Unit 1, the spent fuel storage racks are divided into three regions with different fuel burnup-enrichment limits associated with each region. Fuel assemblies may be stored in any location, as specified in Table 3.7.14-1A, provided the fuel burnup-enrichment combinations are within the limits specified for the associated storage rack region in the accompanying LCO.

For Unit 1, the spent fuel storage racks are constructed, in part, from a boron carbide and aluminum-composite material with the trade name "Boral." The Boral material provides a neutron absorbing function to maintain the stored fuel in a subcritical condition. Therefore, soluble boron is not required in the Unit 1 spent fuel pool to maintain the spent fuel rack multiplication factor, k_{eff} , $\leq$ 0.95 when the fuel assemblies are stored in the correct fuel pool location in accordance with the accompanying LCO and no fuel movement is in progress (i.e., the pool is in a static condition). The fact that soluble boron concentration is not required to maintain the Unit 1 spent fuel rack multiplication factor, k_{eff} , $\leq$ 0.95 is confirmed in Holtec Report HI-92791 (Ref. 1). However, a boron concentration is maintained in the Unit 1 spent fuel pool to provide negative reactivity for postulated accident conditions (i.e., a misplaced fuel assembly resulting from fuel movement) consistent with the guidelines of ANSI 16.1-1975 (Ref. 2) and the April 1978 NRC letter (Ref. 3). The required Unit 1 spent fuel pool boron concentration for a reactivity excursion due to accident conditions is 1050 ppm.

Safe operation of the Unit 1 spent fuel pool with no movement of assemblies may therefore be achieved (without reliance on soluble boron) by controlling the location of each stored fuel assembly in accordance with the accompanying LCO.

BASES

BACKGROUND (continued)

Boraflex Racks

For Unit 2, spent fuel storage is dictated by four different storage configurations associated with fuel burnup, enrichment, decay, interface and Integral Fuel Burnable Absorber (IFBA) requirements. Fuel assemblies must be stored in the configurations specified in Table 3.7.14-1B or Specification 4.3.1.1.e.

For Unit 2, new or partially spent fuel assemblies within the limits of Table 3.7.14-1B may be allowed unrestrictive storage in the fuel storage racks. New or partially spent fuel assemblies not within the limits of Table 3.7.14-1B will be stored in compliance with Specification 4.3.1.1.e, Reference 4.

In the first Unit 2 configuration, designated as “All-Cell”, Westinghouse 17x17 standard fuel assemblies can be stored in a repeating 2x2 matrix of storage cells where all the assemblies have nominal enrichments less than or equal to 1.856 w/o U-235. Fuel assemblies with initial nominal enrichments greater than 1.856 w/o U-235 must satisfy a minimum burnup requirement as shown in Table 3.7.14-1B, to be eligible for storage in this configuration.

In the second Unit 2 configuration, designated as “3x3”, Westinghouse 17x17 standard fuel assemblies can be stored in a repeating 3x3 matrix of storage cells with eight storage cell locations forming a ring of depleted fuel assemblies that surround a fuel assembly with initial nominal enrichment up to 5.0 w/o. The depleted fuel assemblies for this configuration must have an initial nominal enrichment of less than or equal to 1.194 w/o U-235, or satisfy a minimum burnup requirement for higher initial enrichments as shown in Reference 4 for this configuration. The burnup requirements for the depleted assemblies in this configuration can be reduced by crediting decay time.

In the third Unit 2 configuration, designated as “1-out-of-4 5.0 w/o at 15,000 MWD/MTU”, Westinghouse 17x17 standard fuel assemblies can be stored in a repeating 2x2 matrix of storage cells with a fuel assembly having an initial nominal enrichment of up to 5.0 w/o U-235 and a burnup of at least 15,000 MWD/MTU occupying one storage cell location and depleted fuel assemblies occupying the three remaining locations. The depleted fuel assemblies for this configuration must have an initial nominal enrichment of less than or equal to 1.569 w/o U-235, or satisfy a minimum burnup requirement for higher initial enrichments as shown in Reference 4 for this configuration.

BASES

BACKGROUND (continued)

In the fourth Unit 2 configuration, designated as “1-out-of-4 3.85 w/o with IFBA”, Westinghouse 17x17 standard fuel assemblies can be stored in a repeating 2x2 matrix of storage cells with a fuel assembly having nominal initial enrichment up to 3.85 w/o U-235 occupying one of the four storage cell locations and depleted fuel assemblies occupying the three remaining locations. The depleted fuel assemblies for this configuration must have an initial nominal enrichment of less than or equal to 1.279 w/o U-235, or satisfy a minimum burnup requirement for higher initial enrichments as shown in Reference 4 for this configuration. The fresh fuel assembly must have an initial nominal enrichment of less than or equal to 3.85 w/o U-235, or must contain a minimum number of IFBA pins for higher initial enrichments as shown in Reference 4 for this configuration. The IFBA stack in the fresh assemblies must be at least 120 inches long and have a nominal loading of at least 1.5X to meet the requirements.

For Unit 2, the interfaces between these four configurations must be maintained such that only the depleted assemblies from each of the configurations are located along the interface. Using the depleted assemblies at the interface precludes locating the more highly reactive assemblies (fresh or 15,000 MWD/MTU) next to each other where the configurations meet. Each configuration has its own requirements for its depleted assemblies, which are identified in Reference 4. In the case of the “All-Cell” configuration, all of the assemblies are depleted and, therefore, can be located at the interface with any of the other configurations.

For Unit 2, spent fuel racks have been analyzed in accordance with the methodology contained and documented in Reference 4. This methodology ensures the spent fuel rack multiplication factor, k_{eff}, is $\leq$ 0.95 as recommended by the April 1978 NRC letter (Ref. 3) and ANSI/ANS-57.2-1983 (Ref. 6). The codes, methods, and techniques contained in the methodology are used to satisfy this k_{eff} criterion.

The four storage configurations for the Unit 2 spent fuel storage racks are analyzed for a range of initial assembly enrichment up to 5.0 w/o utilizing credit for burnup, burnable absorbers, decay time and soluble boron, to ensure k_{eff} is maintained $\leq$ 0.95, including uncertainties, tolerances, and accident conditions. The Unit 2 spent fuel storage pool k_{eff} is maintained < 1.0, including uncertainties and tolerances on a 95/95 probability/confidence level, without crediting soluble boron.

Therefore, the safe operation of the Unit 2 spent fuel storage pool with no movement of assemblies necessitates both the storage requirements of this Specification as well as the fuel pool boron concentration requirements of LCO 3.7.16 be met.

BASES

BACKGROUND (continued)

Metamic Racks

For Unit 2, the spent fuel storage racks are constructed, in part, from a boron carbide and aluminum-composite material with the trade name "Metamic." The Metamic material provides a neutron absorbing function to maintain the stored fuel in a subcritical condition. The criticality analysis, documented in Holtec Report HI-2084175 (Ref. 5), demonstrates that the effective neutron multiplication factor (k_{eff}) is less than 1.0 with the storage racks fully loaded with fuel of the highest anticipated reactivity and the pool flooded with unborated water at a temperature corresponding to the highest reactivity. The criticality analysis also demonstrates that k_{eff} is less than or equal to 0.95 with the storage racks fully loaded with fuel of the highest anticipated reactivity and the pool flooded with borated water at a temperature corresponding to the highest reactivity. In addition, soluble boron is required in the Unit 2 spent fuel storage pool to provide negative reactivity for postulated accident conditions (i.e., a misplaced fuel assembly resulting from fuel movement) consistent with the guidelines of the April 1978 NRC letter (Ref. 3) and ANSI/ANS-57.2-1983 (Ref. 6).

Therefore, as was the case for the Boraflex racks, the safe operation of the Unit 2 spent fuel storage pool with no movement of assemblies necessitates that both the storage requirements of this Specification as well as the fuel pool boron concentration requirements of LCO 3.7.16 be met.

For the Unit 2 high-density Metamic racks, fuel storage locations are dictated by three different regions in each rack, associated with fuel type group (enriched blankets, natural blankets, or no blankets), enrichment, and burnup. Fuel assemblies must be characterized based on these three parameters, and stored in the regions specified in Table 3.7.14-1C (enriched blankets), Table 3.7.14-1D (natural blankets), Table 3.7.14-1E (no blankets), and Specification 4.3.1.1.e. In addition to the information provided in these specifications, details about the different fuel type groups and figures illustrating the storage location regions are provided in Reference 5.

BASES

APPLICABLE SAFETY ANALYSES

The hypothetical accidents can only take place during or as a result of the movement of an assembly (Ref. 7). For these accident occurrences, the presence of soluble boron in the spent fuel storage pool (controlled by LCO 3.7.16, "Fuel Storage Pool Boron Concentration") prevents criticality in the spent fuel storage pool. By closely controlling the movement of each assembly and by checking the location of each assembly after movement, the time period for potential accidents may be limited to a small fraction of the total operating time. Conformance with the applicable spent fuel storage pool criticality analyses is assured through compliance with the accompanying LCO and refueling procedures.

For Unit 1, during the remaining time period with no potential for accidents, the operation may be under the auspices of the accompanying LCO without reliance on soluble boron.

For Unit 2, however, when no potential for an accident exists, safe operation of the spent fuel storage pool must include the boron concentration within the limit specified in LCO 3.7.16 as well as the fuel being stored in accordance with LCO 3.7.14. The boron concentration specified in LCO 3.7.16, as well as the storage requirements of LCO 3.7.14, are necessary to meet the requirement to maintain $k_{eff} \leq 0.95$ in the Unit 2 spent fuel storage pool under normal (i.e., static) conditions. Operation within the storage requirements of LCO 3.7.14 with no soluble boron in the Unit 2 spent fuel storage pool maintains $k_{eff} < 1.0$, including uncertainties and tolerances on a 95/95 probability/confidence level. In accordance with Reference 4, the interface boundaries between the various storage requirement configurations of the Boraflex racks are maintained such that only the depleted assemblies are at the boundary. In accordance with Reference 5, this restriction is not applicable to the assemblies stored in the Metamic racks.

The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

For Unit 1, the restrictions on the placement of fuel assemblies within the spent fuel pool, in accordance with Table 3.7.14-1A, in the accompanying LCO, ensures the k_{eff} of the spent fuel storage pool will always remain ≤ 0.95, assuming the pool to be flooded with unborated water.

<u>Boraflex Racks</u>

For Unit 2, operation within the storage requirements specified in Table 3.7.14-1B of the accompanying LCO or Specification 4.3.1.1.e, with no soluble boron in the spent fuel storage pool would only maintain $k_{eff} < 1.0$, including uncertainties and tolerances on a 95/95 probability/confidence

BASES

LCO (continued)

level. Therefore, Unit 2 must also maintain the spent fuel storage pool boron concentration within the limit specified in LCO 3.7.16, in order to meet the requirement to maintain $k_{eff} \leq 0.95$.

Metamic Racks

For Unit 2 storage of fuel in the Metamic racks, required locations are dictated by three different regions in each rack, associated with fuel type group (enriched blankets, natural blankets, or no blankets), enrichment, and burnup. Fuel assemblies must be characterized based on these three parameters, and stored in the regions specified in Table 3.7.14-1C (enriched blankets), Table 3.7.14-1D (natural blankets), Table 3.7.14-1E (no blankets), and Specification 4.3.1.1.e.

For Unit 2, storage of fuel in the Metamic racks within the storage requirements specified in LCO 3.7.14 and Specification 4.3.1.1.e, with no soluble boron in the spent fuel storage pool, would only maintain $k_{eff} < 1.0$, including uncertainties and tolerances on a 95/95 probability/confidence level. Therefore, Unit 2 must also maintain the spent fuel storage pool boron concentration within the limit specified in LCO 3.7.16, in order to meet the requirement to maintain $k_{eff} \leq 0.95$.

For Unit 2, Specification 4.3.1.1.e contains a requirement that two empty rows of storage cells shall exist between the fuel assemblies stored in a Boraflex rack and the fuel assemblies stored in an adjacent Metamic rack in the fuel storage pool. The need for the two empty rows is to ensure that the fuel in the two types of racks is neutronically decoupled during the installation phase of the reracking project. In order to also resolve a potential seismic interaction issue between the two different types of racks, the two empty rows of storage cells must either both be in the Boraflex rack or may consist of a single empty row in each type of rack. This spacing requirement does not need to be imposed on fuel in racks adjacent to the same type of rack.

The LCO is modified by a Note, applicable to Unit 2 only, stating that the Technical Specification requirements applicable to the fuel storage pool are also applicable to the fuel cask area when a fuel assembly is in the fuel cask area during the installation phase of the Unit 2 reracking project.

BASES

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in the fuel storage pool (also referred to in several locations within the specifications as the spent fuel storage pool or the spent fuel pool).

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the configuration of fuel assemblies stored in the spent fuel storage pool is not in accordance with Table 3.7.14-1A for Unit 1 and the LCO for Unit 2, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Table 3.7.14-1A for Unit 1 and LCO 3.7.14 for Unit 2.

The Required Actions are modified by a Note that takes exception to LCO 3.0.3. If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with Table 3.7.14-1A for Unit 1, and in accordance with the requirements of LCO 3.7.14 for Unit 2.

Verification by administrative means may be accomplished through fuel receipt records for new fuel or burnup analysis as necessary in accordance with refueling procedures. The Frequency of prior to storing a fuel assembly ensures that fuel assemblies are stored within the configurations analyzed in the spent fuel criticality analyses.

BASES

REFERENCES

1. Holtec Report HI-92791, Rev. 6, "Spent Fuel Pool Modification For Increased Storage Capacity, Beaver Valley Power Station Unit 1," April 1992 as supplemented by Letter to the NRC (License Change Request No. 202, Supplement 1, Spent Fuel Pool Rerack) dated June 28, 1993, and as further supplemented by calculation 8700-DMC-3664, Rev. 0.

2. ANSI 16.1-1975 (ANS-8.1), Nuclear Criticality Safety In Operations With Fissionable Materials Outside Reactors.

3. NRC Letter to All Power Reactor Licensees from B. K. Grimes, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," April 14, 1978.

4. WCAP-16518-P, "Beaver Valley Unit 2 Spent Fuel Rack Criticality Analysis," Revision 2, July 2007.

5. Holtec Report HI-2084175, Revision 8, "Licensing Report for Beaver Valley Unit 2 Rerack," as submitted to the NRC in support of License Amendment No. 173, Unit 2 Fuel Storage Pool Rerack.

6. ANSI/ANS-57.2-1983, "Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations."

7. UFSAR Section 14 (Unit 1) and UFSAR Section 15 (Unit 2).

B 3.7 PLANT SYSTEMS

B 3.7.15 Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident (FHA). The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the fuel storage pool design is given in the UFSAR, Section 9.12 (Unit 1) and Section 9.1.2 (Unit 2) (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in the UFSAR, Section 9.5 (Unit 1) and Section 9.1.3 (Unit 2) (Ref. 2). The assumptions of the FHA are given in the UFSAR, Section 14.2.1 (Unit 1) and Section 15.7.4 (Unit 2) (Ref. 3).

APPLICABLE SAFETY ANALYSES

The minimum water level in the fuel storage pool meets the assumptions of the FHA described in Regulatory Guide 1.183 (Ref. 4). The resultant offsite and control room doses are within the 10 CFR 50.67 (Ref. 5) and Reference 4 limits.

According to Reference 3, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a FHA. With 23 ft of water, the decontamination factors of Reference 4 can be used directly. In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, however, there may be $<$ 23 ft of water above the top of the fuel bundle and the surface, indicated by the width of the bundle. To offset this small nonconservatism, the analysis assumes that the maximum number of postulated fuel rods fail. This number of failed fuel rods is based on the worse case postulated fuel drop height occurring in the containment building. The postulated fuel drop height in the fuel building is significantly less than the postulated fuel drop height in the containment building.

The FHA in the storage pool is described in Reference 3. With a minimum water level of 23 feet and a minimum decay time of 100 hours prior to fuel handling, the analyses demonstrate that the offsite and control room doses are maintained within the limits established in References 4 and 5.

The fuel storage pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The fuel storage pool water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 3). As such, it is the minimum required for fuel movement within the fuel storage pool.

As clarified in the LCO 3.7.14 NOTE, applicable to Unit 2 only, Specification 3.7.15 applies to the fuel cask area when a fuel assembly is in the cask area during the installation phase of the Unit 2 rerack project.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the fuel storage pool and during movement of fuel assemblies over irradiated fuel assemblies in the fuel storage pool, since the potential for a release of fission products exists.

ACTIONS

Condition A is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

A.1

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the fuel storage pool water level is lower than the required level, the movement of irradiated fuel assemblies in the fuel storage pool is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

A.2

When the fuel storage pool water level is lower than the required level, the movement of non-irradiated fuel assemblies over irradiated fuel assemblies in the fuel storage pool is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies sufficient fuel storage pool water is available in the event of a fuel handling accident. The water level in the fuel storage pool must be checked periodically. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

In addition to verifying the storage pool level at the Frequency specified in the Surveillance Frequency Control Program, during refueling operations, with the transfer tube open, the level in the fuel storage pool is in equilibrium with the refueling cavity, and the level in the refueling cavity is checked daily in accordance with SR 3.9.6.1.

REFERENCES

1. UFSAR, Section 9.12 (Unit 1) and Section 9.1.2 (Unit 2).
2. UFSAR, Section 9.5 (Unit 1) and Section 9.1.3 (Unit 2).
3. UFSAR, Section 14.2.1 (Unit 1) and Section 15.7.4 (Unit 2).
4. Regulatory Guide 1.183, July 2000.
5. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.16 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

The spent fuel storage racks contain storage locations for 1627 fuel assemblies (Unit 1) and 1088 fuel assemblies when the spent fuel storage pool contains only Boraflex racks or 1690 fuel assemblies when the spent fuel storage pool contains only Metamic racks (Unit 2). The racks are designed to store Westinghouse 17X17 fuel assemblies with nominal enrichment up to 5.0 weight percent.

For Unit 1, the spent fuel storage racks are divided into three regions with different fuel burnup-enrichment limits associated with each region. Fuel assemblies may be stored in any location, as specified in Table 3.7.14-1A, provided the fuel burnup-enrichment combinations are within the limits specified for the associated storage rack region in LCO 3.7.14, "Spent Fuel Assembly Storage."

For Unit 1, the spent fuel storage racks are constructed, in part, from a boron carbide and aluminum-composite material with the trade name "Boral." The Boral material provides a neutron absorbing function that helps to maintain the stored fuel in a subcritical condition. Therefore, soluble boron is not required in the Unit 1 spent fuel pool to maintain the spent fuel rack multiplication factor, k_{eff} , $\leq$ 0.95 when the fuel assemblies are stored in the correct fuel pool location in accordance with LCO 3.7.14 and no fuel movement is in progress (i.e., the pool is in a static condition). The fact that soluble boron concentration is not required to maintain the Unit 1 spent fuel rack multiplication factor, k_{eff} , $\leq$ 0.95 is confirmed in Holtec Report HI-92791 (Ref. 1). However, a boron concentration is maintained in the Unit 1 spent fuel pool to provide negative reactivity for postulated accident conditions (i.e., a misplaced fuel assembly resulting from fuel movement) consistent with the guidelines of ANSI 16.1-1975 (Ref. 2) and the April 1978 NRC letter (Ref. 3). The required Unit 1 spent fuel pool boron concentration for a reactivity excursion due to accident conditions is 1050 ppm.

Safe operation of the Unit 1 spent fuel pool with no movement of assemblies may therefore be achieved (without reliance on soluble boron) by controlling the location of each stored fuel assembly in accordance with LCO 3.7.14. However, prior to fuel movement and during movement of fuel assemblies it is necessary to perform SR 3.7.16.1 to assure the required boron concentration is available until fuel movement is finished and a verification is complete that assures fuel assemblies are stored in accordance with LCO 3.7.14.

BASES

BACKGROUND (continued)

Boraflex Racks

For Unit 2, the Boraflex spent fuel racks have been analyzed in accordance with the methodology contained and documented in Reference 4. This methodology ensures the spent fuel rack multiplication factor, k_{eff}, is $\leq$ 0.95 as recommended by the April 1978 NRC letter (Ref. 3) and ANSI/ANS-57.2-1983 (Ref. 6). The codes, methods, and techniques contained in the methodology are used to satisfy this k_{eff} criterion.

The four storage configurations for the Unit 2 Boraflex spent fuel storage racks are analyzed for a range of initial assembly enrichment up to 5.0 w/o utilizing credit for burnup, burnable absorbers, decay time and soluble boron, to ensure k_{eff} is maintained $\leq$ 0.95, including uncertainties, tolerances, and accident conditions.

Metamic Racks

For Unit 2, the Metamic spent fuel racks have been analyzed in accordance with the methodology contained and documented in Reference 5. This methodology ensures the spent fuel rack multiplication factor, k_{eff}, is $\leq$ 0.95 as recommended by the April 1978 NRC letter (Ref. 3) and ANSI/ANS-57.2-1983 (Ref. 6). The codes, methods, and techniques contained in the methodology are used to satisfy this k_{eff} criterion.

The three storage regions for the Unit 2 Metamic spent fuel storage racks are analyzed for a range of initial assembly enrichment up to 5.0 w/o utilizing credit for burnup, to ensure k_{eff} is maintained $\leq$ 0.95, including uncertainties, tolerances, and accident conditions. The three fuel storage location regions are described in Specification 4.3.1.1.e, and in Reference 5.

The soluble boron concentration required to maintain $k_{eff} \leq 0.95$ in the Unit 2 spent fuel storage pool under normal conditions has been determined for when the spent fuel storage pool contains only Boraflex racks (Ref. 4) and when the spent fuel storage pool contains only Metamic racks (Ref. 5). When the spent fuel storage pool contains only Boraflex racks the required concentration is 450 ppm. When the spent fuel storage pool contains only Metamic racks the required concentration is 495 ppm. For conservatism, 495 ppm is specified in Specification 4.3.1.1.c.

BASES

BACKGROUND (continued)

A spent fuel storage pool boron concentration of 2000 ppm ensures no credible boron dilution event will result in k_{eff} exceeding 0.95. Safe operation of the Unit 2 spent fuel storage pool with either type of rack requires the specified fuel pool boron concentration be maintained at all times when fuel assemblies are stored in the spent fuel storage pool. Therefore, for Unit 2, SR 3.7.16.1 is applicable whenever fuel assemblies are stored in the spent fuel storage pool with either type of rack.

During refueling, the water volume in the spent fuel storage pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

APPLICABLE SAFETY ANALYSES

The most limiting reactivity excursion event evaluated in the spent fuel pool criticality analyses (for both Unit 1 and 2) is a misplaced new fuel assembly with the highest permissible U-235 enrichment (5.0 weight percent).

For Unit 1, the amount of soluble boron required to maintain the spent fuel rack multiplication factor, k_{eff}, $\leq$ 0.95 with the worst case misplaced new fuel assembly is approximately 400 ppm. The $\geq$ 1050 ppm boron concentration specified in the Unit 1 LCO conservatively assures k_{eff} is maintained within the limit for the worst case misplaced assembly accident. The Unit 1 boron concentration requirement of 1050 ppm includes a conservative margin of 600 ppm with a 50 ppm allowance for uncertainties.

Boraflex Racks

For Unit 2, with only Boraflex racks, the amount of soluble boron required to maintain the spent fuel storage rack multiplication factor, k_{eff}, $\leq$ 0.95 with the worst case misplaced new fuel assembly is $\geq$ 837 ppm.

Metamic Racks

For Unit 2, with only Metamic racks the amount of soluble boron required to maintain the spent fuel storage rack multiplication factor, k_{eff}, $\leq$ 0.95 for the worst case accident, i.e., a misplaced new fuel assembly in the outer row of the rack in a Region 2 location, is $\geq$ 1212 ppm.

When the spent fuel storage pool contains a combination of racks, the amount of soluble boron required to maintain the spent fuel storage rack multiplication factor, k_{eff}, $\leq$ 0.95 with the worst case misplaced new fuel assembly is conservatively specified as $\geq$ 1212 ppm.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For either type of rack, the ≥ 2000 ppm limit specified in the Unit 2 LCO conservatively assures k_{eff} is maintained within the limit for the worst case misplaced fuel assembly accident. In addition, the ≥ 2000 ppm limit specified in the Unit 2 LCO ensures no credible boron dilution event will reduce the boron concentration below the 495 ppm required during normal non-accident conditions to maintain $k_{eff} \leq 0.95$ for either type of rack.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The fuel storage pool boron concentration is required to be ≥ 1050 ppm (Unit 1) and ≥ 2000 ppm (Unit 2). The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential criticality accidents as discussed in the UFSAR (Ref. 7). In addition, for Unit 2, soluble boron is credited to maintain $k_{eff} \leq 0.95$ during normal operating conditions whenever fuel is stored in the spent fuel storage pool.

As clarified in the LCO 3.7.14 Note, applicable to Unit 2 only, Specification 3.7.16 applies to the fuel cask area when a fuel assembly is in the cask area during the installation phase of the Unit 2 rerack project.

APPLICABILITY

For Unit 1 this LCO applies whenever fuel assemblies are stored in the spent fuel storage pool, until a complete spent fuel storage pool verification has been performed following the last movement of fuel assemblies in the spent fuel storage pool. This LCO does not apply to Unit 1 following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

For Unit 2 this LCO applies whenever fuel assemblies are stored in the spent fuel storage pool to ensure k_{eff} is maintained ≤ 0.95 during normal operation as well as for potential criticality accident scenarios.

ACTIONS

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

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

BASES

ACTIONS (continued)

In addition, Required Action A.2.2 is modified by a Note that states Required Action A.2.2 is only applicable to Unit 1. The Action is restricted to Unit 1 because Unit 1 does not credit soluble boron during normal (non-accident) conditions to ensure k_{eff} is maintained $\leq$ 0.95.

When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. Action is also initiated to restore the boron concentration simultaneously with suspending movement of fuel assemblies. Alternatively, for Unit 1 only, beginning a verification of the fuel storage pool fuel locations, to ensure proper locations of the fuel, can be performed. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

The Required Actions are modified by a Note that takes exception to LCO 3.0.3. If the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

For Unit 1 the Surveillance must be performed within the specified Frequency prior to initiating fuel movement and must continue to be performed at the specified Frequency until fuel movement is finished and a verification is complete that assures fuel assemblies are stored in accordance with LCO 3.7.14.

For Unit 2 the Surveillance must be performed within the specified Frequency whenever fuel assemblies are stored in the spent fuel storage pool.

BASES

REFERENCES

1. Holtec Report HI-92791, Rev. 6, "Spent Fuel Pool Modification For Increased Storage Capacity, Beaver Valley Power Station Unit 1," April 1992 as supplemented by Letter to the NRC (License Change Request No. 202, Supplement 1, Spent Fuel Pool Rerack) dated June 28, 1993, and as further supplemented by calculation 8700-DMC-3664, Rev. 0.

2. ANSI 16.1-1975 (ANS-8.1), Nuclear Criticality Safety In Operations With Fissionable Materials Outside Reactors.

3. NRC Letter to All Power Reactor Licensees from B. K. Grimes, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," April 14, 1978.

4. WCAP-16518-P, “Beaver Valley Unit 2 Spent Fuel Rack Criticality Analysis,” Revision 2, July 2007.

5. Holtec Report HI-2084175, Revision 8, "Licensing Report for Beaver Valley Unit 2 Rerack," as submitted to the NRC in support of License Amendment 173, Unit 2 Fuel Storage Pool Rerack.

6. ANSI/ANS-57.2-1983, "Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations."

7. UFSAR Sections 3.3.2.7 and 9.12.2.2 (Unit 1) and UFSAR Sections 4.3.2.6 and 9.1.2 (Unit 2).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternate(s)), and the onsite standby power sources (Train A and Train B diesel generators (DGs)). As discussed in Reference 1, the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to one required offsite power source and a single DG.

Offsite power is supplied to the switchyard from several 345kV and 138kV transmission lines. From the switchyard(s), two electrically and physically separated circuits provide AC power, through step down station service transformers, to the 4.16 kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs 1-1 for Unit 1 and 2-1 for Unit 2 and 1-2 for Unit 1 and 2-2 for Unit 2 are dedicated to ESF buses AE and DF, respectively. A DG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure, steamline pressure - low, manual, or high containment pressure signals) or on an undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer timer(s). The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

BASES

BACKGROUND (continued)

The sequence timer(s) provide a time delay for the individual component to close its breaker to the associated emergency electrical bus. Each component is sequenced onto the emergency bus by an initiating signal. Improper loading sequence may cause the emergency bus to become inoperable. The Unit 1 sequence timers are provided for each train of ESF components and may affect individual components and the associated DG. The Unit 2 sequence timers affect individual components and the associated DG.

In the event of a loss of unit and system power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute (Reference 2) after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Bus AE Train A and Bus DF Train B DGs satisfy the requirements of Reference 3. The continuous service rating of each DG is for Unit 1 2600 kW and for Unit 2 4238 kW with a 2850 kW (Unit 1) and 4535 kW (Unit 2) allowable for up to 2000 hours per year. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Reference 5 assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or 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

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit.

In addition, required automatic load sequence timer(s) must be OPERABLE.

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

During normal plant operation, electrical power for the onsite circuits comes from either the main generator through 22 kV to 4.36 kV unit station service transformers or from the two independent offsite 138 kV buses through 138 kV to 4.36 kV system station service transformers. The secondary windings of the transformers are connected to four separate 4.16 kV normal buses, A, B, C and D. Buses A and D provide power for the two redundant Class 1E 4.16 kV emergency buses AE and DF, respectively. During plant shutdown, the emergency buses receive power from the system station service transformers, or may receive power from the unit station service transformers by backfeeding the main transformer. Automatic and manual transfer capabilities to the system station service transformers are available when the offsite source(s) are required to be OPERABLE.

Each DG must be capable of starting, accelerating to nominal speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds from the time the signal is received by the DG starting circuit. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional

BASES

LCO (continued)

DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to standby status on an Emergency Core Cooling Systems (ECCS) signal while operating in parallel test mode for Unit 2 only.

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

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, electrical separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit that is not connected to an ESF bus is required to have OPERABLE fast transfer capability to align that circuit to its associated ESF bus.

APPLICABILITY

The AC sources and sequencer timer(s) are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

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

BASES

ACTIONS (continued)

Requirements for applying the 14 day DG Completion Time

The ACTION Conditions for inoperable AC sources provide a 14 day Completion Time when one DG is inoperable. The 14 day Completion Time includes the normal 72 hour Completion Time which is not risk informed, followed by an 11 day extension period that is based on a plant specific risk analysis performed to establish the overall Completion Time (Ref 12).

As a defense in depth measure, when the option of an extended Completion Time (i.e., a time beyond the normal 72 hours) for a DG is exercised, alternate AC (AAC) power will be provided with capability of supplying safe shutdown loads during a station blackout without the need for rescheduling of safety system operation in the unaffected unit. For unplanned DG outages, capability to supply AAC power will be available upon entering the Completion Time extension (i.e., by 72 hours into the Completion Time). For outages planned to exceed an initial 72 hour Completion Time, AAC power will be provided within one hour of entering the Action Condition for an inoperable DG. In any event, if AAC power of the required capacity is not available after entering the extended Completion Time (after 72 hours into the Completion Time), the actions of Required Action G become applicable (i.e., Be in MODE 3 in 6 hours and be in MODE 5 in 36 hours).

The following criteria would apply to any AAC source used as a defense in depth measure:

1. An AAC power source may be of a temporary or permanent nature and would not be required to satisfy Class 1E requirements.

2. Dynamic effects of an AAC power source failure (GDC-4 events) would not adversely affect safety related plant equipment.

3. An AAC power source would not be required to be protected against natural phenomena (GDC-2 events) or abnormal environmental or dynamic effects (GDC-4 events).

4. An AAC power source would be capable of starting and carrying designated loads required for safe shutdown, including maintaining adequate voltage and frequency such that performance of powered equipment is acceptable.

BASES

ACTIONS (continued)

Prior to relying on its availability, a temporary AAC power source would be determined to be available by: (1) starting the AAC source and verifying proper operation; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AAC source is in the correct electrical alignment to supply power to designated safe shutdown loads. Subsequently, when not in operation, a status check for availability will also be performed once every 72 hours. This check consists of: (1) verifying the AAC source is mechanically and electrically ready for operation; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AAC source is in the correct electrical alignment to supply power to designated safe shutdown loads.

Prior to relying on its availability, a permanent AAC power source would be determined to be available by starting the AAC source and verifying proper operation. In addition, initial and periodic testing, surveillance, and maintenance conform to NUMARC 87-00, Revision 1, Appendix B, "Alternate AC Power Criteria" guidelines. The guidelines include provisions for quarterly functional testing, timed starts and load capacity testing on a fuel cycle basis, surveillance and maintenance consistent with manufacturer's recommendations, and initial testing of capability to power required shutdown equipment within the necessary time.

A.1

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

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant required features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. These features are powered from the redundant AC electrical power train.

BASES

ACTIONS (continued)

A single motor driven auxiliary feedwater (AFW) pump does not provide sufficient flow to meet the most limiting accident analysis assumptions. Two out of the three AFW pumps are necessary to assure sufficient flow to meet the accident analyses. Therefore, in order to ensure the AFW safety function is maintained, the turbine driven AFW pump must be considered a redundant required feature for the purposes of this Required Action.

For Unit 2 only, the Train "B" (RHR) ADV cannot provide sufficient steam relief capacity in a prompt enough manner to meet the most limiting accident analysis assumptions upon the onset of a Steam Generator (SG) Tube Rupture until the ruptured SG is isolated from the Train B ADV flow path. Therefore, in order to ensure the ADV steam relief safety function is maintained for the purpose of preventing SG overfill with the "A" train offsite circuit inoperable, the three Train "A" ADVs must be considered a redundant required feature for the purposes of this Required Action. When determining if the required redundant feature(s) are available, as specified in this Required Action, the Train "A" ADVs are only required to be capable of local manual operation.

The Completion Time for Required Action A.2 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. The train has no offsite power supplying its loads and

b. A required feature on the other train is inoperable.

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

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train 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 subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. 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.

BASES

ACTIONS (continued)

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. 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 unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

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

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. The following discussion and the 17 day Completion Time stated in the Action Condition assume the extended 14 day DG Completion Time is applied (see the requirements for applying the extended DG Completion Time discussed at the beginning of the Actions section of the Bases). If the Normal 72 hour DG Completion Time is applied, the limiting Completion Time for not meeting the LCO discussed below would be 144 hours (72 hours plus 72 hours) instead of 17 days (72 hours plus 14 days).

If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with an inoperable DG, 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 and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical redundant required features. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

A single motor-driven AFW pump does not provide sufficient flow to meet the most limiting accident analysis assumptions. Two out of the three AFW pumps are necessary to assure sufficient flow to meet the accident analyses. Therefore, in order to ensure the AFW safety function is maintained, the turbine-driven AFW pump must be considered a redundant required feature for the purposes of this Required Action.

For Unit 2 only, the Train "B" (RHR) ADV cannot provide sufficient steam relief capacity in a prompt enough manner to meet the most limiting accident analysis assumptions upon the onset of a Steam Generator (SG) Tube Rupture until the ruptured SG is isolated from the Train B ADV flow path. Therefore, in order to ensure the ADV steam relief safety function is maintained for the purpose of preventing SG overfill with the "A" train DG inoperable, the three Train "A" ADVs must be considered a redundant required feature for the purposes of this Required Action. When determining if the required redundant feature(s) are available, as specified in this Required Action, the Train "A" ADVs are only required to be capable of local manual operation.

The Completion Time for Required Action B.2 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:

BASES

ACTIONS (continued)

a. An inoperable DG exists and

b. A required feature on the other train (Train A or Train B) is inoperable.

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

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

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

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. Examples of these activities, which do not require performance of SR 3.8.1.2 for the OPERABLE DG, include testing, preplanned preventative maintenance, and individual testable components. If the cause of inoperability exists on another DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

BASES

ACTIONS (continued)

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

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.4

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time is risk informed and based on a plant specific risk analysis and includes the normal 72 hour Completion Time which is not risk informed. The Completion Time also 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. The Completion Time specified for Required Action B.4 is the extended 14 day DG Completion Time (see the requirements for applying the extended DG Completion Time discussed at the beginning of the Actions section of the Bases). If the requirements for the 14 day Completion Time are not met, the normal 72 hour Completion Time applies. If the 14 day Completion Time is applied, and if at any time during this extended Completion Time the requirements for using the 14 day Completion Time are not met, the 72 hour Completion Time becomes applicable unless the 72 hour Completion Time has expired, in which case the shutdown requirements of Required Action G would apply.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. The following discussion and the Completion Times specified for Required Action B.4 assume the extended 14 day DG Completion Time is applied (see the requirements for applying the extended DG Completion Time discussed at the beginning of the Actions section of the Bases). If the normal 72 hour DG Completion Time is applied, the limiting Completion Time for not meeting the LCO discussed below would be 144 hours (72 hours plus 72 hours) instead of 17 days (72 hours plus 14 days).

BASES

ACTIONS (continued)

If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

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 to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant required features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. These features are powered from redundant AC safety trains. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains 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. All required offsite circuits are inoperable and

b. A required feature is inoperable.

BASES

ACTIONS (continued)

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

BASES

ACTIONS (continued)

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

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

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

BASES

ACTIONS (continued)

F.1.1, F.1.2, and F.2

Condition F is entered any time a required sequence timer(s) becomes inoperable. Required Action F.1.1 requires that action be taken immediately to place the affected component (ESF equipment) in a condition where it can not be automatically loaded to its emergency bus. Required Action F.1.1 provides assurance that the DG loading sequence will not be adversely affected by the inoperable sequence timer(s) (i.e., the component will not be loaded onto an emergency bus at an incorrect time). Therefore, rendering a component with an inoperable sequence timer(s) incapable of loading to the emergency bus prevents a possible overload condition. Required Action F.1.2 requires that the appropriate Condition and Required Actions associated with the affected individual component(s) made inoperable by the inoperable sequence timer(s) be applied immediately. Thus, Required Actions F.1.1 and F.1.2 serve to isolate the affected component(s) from the emergency bus and assure the appropriate remedial measures for the affected component(s) are taken in a timely manner. Required Action F.2 provides an alternative option to Required Actions F.1.1 and F.1.2. Required Action F.2 simply requires that the associated DG be immediately declared inoperable.

A Note modifies Condition F. The Note states that separate Condition entry is allowed for each inoperable sequence timer(s) for a DG.

G.1 and G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

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

BASES

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, as discussed in Reference 8. Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Reference 3, Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage for Unit 1 is 4106 V and for Unit 2 is 3994 V. The SR value bands specified for voltage and frequency for each Unit are analysis values, except for the frequency values of 58.8 Hz to 61.2 Hz specified for Unit 1 in SRs 3.8.1.2 and 3.8.1.8. These Unit 1 Frequency tolerances are Regulatory Guide 1.9 recommendations.

NOTE: The voltage and frequency values specified in each SR need to be reduced or increased, as appropriate, to account for measurement uncertainties.

The specified maximum steady state output voltage of 4368 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.

NOTE: The kW and power factor requirements specified in the SRs are indicated values.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.2

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

To minimize the wear on moving parts that do not get lubricated when the engine is not running, the SR is modified by Note 1 to indicate that all DG starts for this Surveillance may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purpose of SR 3.8.1.2 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations. Barring of the engine may be performed prior to DG start without invalidating SR for starting from standby conditions.

In order to reduce stress and wear on diesel engines, some manufacturers recommend a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2, which is only applicable when such modified start procedures are recommended by the manufacturer.

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

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads equivalent to the continuous duty rating of the DG. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

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

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by four Notes. Note 1 indicates 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 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients outside the normal operating range do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4.1 and SR 3.8.1.4.2

For Unit 1, this SR provides verification that the inventory of fuel oil in the day tank in combination with the engine mounted tank is greater than or equal to the required fuel oil inventory. The required Unit 1 inventory is expressed as an equivalent usable volume in gallons and is selected to ensure the DG can operate for more than 1 hour at full load plus 10%. For Unit 2, this SR provides verification that the inventory of fuel oil in the day tank is greater than or equal to the required fuel oil inventory. The required Unit 2 inventory is expressed as an equivalent usable volume in gallons and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SRs are modified by Notes that specify the applicable unit.

SR 3.8.1.5.1 and SR 3.8.1.5.2

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from these fuel oil 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 DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. This SR is for

BASES

SURVEILLANCE REQUIREMENTS (continued)

preventative maintenance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump (only one pump required per DG) operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for fuel transfer systems are OPERABLE.

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

SR 3.8.1.7

Transfer of each 4.16 kV ESF bus power supply from the unit circuit to the system offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.8

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined frequency and while maintaining a specified margin to the overspeed trip. The single load for each DG is as follows: For Unit 1 615 kW with a frequency limit of 66.2 Hz (993 RPM). For Unit 2 825 kW with a frequency limit of 64.4 Hz (552 RPM). This Surveillance may be accomplished by either:

BASES

SURVEILLANCE REQUIREMENTS (continued)

a. Tripping the DG output breaker or tripping the emergency feeder breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or

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

Consistent with the recommendations of Reference 11, the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

The time, voltage, and frequency tolerances specified in this SR are derived from Reference 3 recommendations for response during load sequence intervals. The 3 and 4 seconds specified are equal to 60% and 80%, respectively, of a typical 5 second load sequence interval associated with sequencing of the largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.8.a corresponds to the maximum frequency excursion, while SR 3.8.1.8.b and SR 3.8.1.8.c are steady state voltage and frequency values to which the system must recover following load rejection. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow 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 Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the 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 the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Note 2 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.89. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 2 allows the surveillance to be conducted at a power factor other than ≤ 0.89. These conditions may occur, for example, when the grid voltage is such that the DG excitation levels needed to obtain a power factor of 0.89 are in excess of those recommended for the DG. In cases such as this, the power factor shall be maintained as close as practicable to 0.89 without exceeding any applicable limits.

SR 3.8.1.9

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

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

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow 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 Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the 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 the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates that the DGs can start and run continuously at or near full load conditions for not less than 8 hours. The Surveillance requires that each DG be run for ≥ 2 hours loaded from a minimum of the calculated accident load for Unit 1, and the continuous duty rating of the DG for Unit 2, up to a maximum loading of the 2000 hour rating for each DG. Additionally, the Surveillance requires that each DG be run for the remainder of the 8-hour requirement loaded to the equivalent of the continuous duty rating of the DG. The required run duration of 8 hours is consistent with the recommendations of IEEE Standard 387-1995 (Ref. 13). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

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

This Surveillance is modified by three Notes. Note 1 provides an allowance such that momentary transients due to changing bus loads do not invalidate this test. The allowance provided by Note 1 includes the transition between the required load ranges specified in SR 3.8.1.10 part a and part b. Similarly, momentary power factor transients outside of the power factor required range will not invalidate the test.

The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the 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 the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

Note 3 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of $\leq$ 0.89. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 3 allows the Surveillance to be conducted at a power factor other than $\leq$ 0.89. These conditions may occur, for example, when the grid voltage is such that the DG excitation levels needed to obtain a power factor of 0.89 are in excess of those recommended for the DG. In cases such as this, the power factor shall be maintained close as practicable to 0.89 without exceeding any applicable limits.

SR 3.8.1.11

Consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made. For Unit 1, the Surveillance also verifies that the DG proceeds through its normal shutdown sequence after transferring its load. For Unit 2, the Surveillance verifies that the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the Unit 2 DG to reload if a subsequent loss of offsite power occurs. The Unit 2 DG is considered to be in ready to load status when the DG is at nominal speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timer(s) are reset.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow 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 Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the 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 the Surveillance is performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

For the Unit 2 DGs, demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a LOCA actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at nominal speed and voltage with the DG output breaker open. These provisions for automatic switchover are consistent with the recommendations of IEEE-308 (Ref. 11), paragraph 6.2.6(2).

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

This SR is modified by two Notes. Note 1 states that the SR is applicable to Unit 2 only. The reason for Note 2 is that performing the Surveillance may perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 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,

BASES

SURVEILLANCE REQUIREMENTS (continued)

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, 3, or 4. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.13

Under accident with loss of offsite power conditions loads are sequentially connected to the bus by the automatic load sequence timer(s). The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The verification that each automatic load sequence time is within ± 10% of the required value ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

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

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow 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 Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system

BASES

SURVEILLANCE REQUIREMENTS (continued)

when they are tied together or operated independently for the 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 the Surveillance is performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.14

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

This Surveillance demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow.

In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 10 second start requirement supports the assumptions of the design basis accident analyses described in the UFSAR (Ref. 5). The 10 second timing requirement begins when the DG start signal is received by the DG start circuit and does not include the time it takes the instrumentation to detect a loss of voltage on the emergency busses.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs. Barring of the engine may be performed prior to DG start without invalidating the requirement for starting from standby conditions. The reason for Note 2 is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 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, 3, or 4. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.15

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

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

This SR is modified by two Notes. Note 1 states that the SR is applicable to Unit 2 only. The reason for the second Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. Barring of the engine may be performed prior to DG start without invalidating the requirement for starting from standby conditions.

BASES

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U. S. Nuclear Regulatory Commission General Design Criteria."

2. UFSAR, Chapter 8.

3. Regulatory Guide 1.9, UFSAR Section 8.5 for Unit 1 and UFSAR Chapter 1.8 - 1 for Unit 2.

4. UFSAR, Chapter 6.

5. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.

6. Regulatory Guide 1.93, Rev. 0, December 1974.

7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

8. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U. S. Nuclear Regulatory Commission General Design Criteria."

9. Regulatory Guide 1.108, Rev. 1, August 1977 (Unit 2).

10. Regulatory Guide 1.137, Rev. 1, October 1979 (Unit 2).

11. IEEE Standard 308 Unit 1-1971 and Unit 2-1974.

12. License Amendment Nos. 268 (Unit 1) and 150 (Unit 2) and associated NRC Safety Evaluation Report issued September 29, 2005.

13. IEEE Standard 387-1995.

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."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6 and during movement of irradiated fuel assemblies or movement of fuel assemblies over irradiated fuel assemblies for Unit 1 (which includes recently irradiated fuel) and during movement of recently irradiated fuel assemblies or movement of fuel assemblies over recently irradiated fuel assemblies for Unit 2 ensure that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods,

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The current fuel handling accident safety analysis does not rely on the automatic actuation of any systems or components to mitigate the accident. Furthermore, the current fuel handling accident analysis does not assume isolation or filtration to mitigate the event. However, in order to limit the control room dose following a fuel handling accident, Unit 1 must purge the control room atmosphere for 30 minutes following termination of the release (2 hours after the accident). The required Unit 1 purge is a manual action for which the Technical Specifications require power (LCO 3.8.2) and ventilation system (LCO 3.7.11) OPERABILITY when moving any irradiated fuel assemblies or fuel assemblies over any irradiated fuel assemblies. The Unit 1 requirement to purge the control room after a fuel handling accident involving any type of irradiated fuel is the reason for the difference in the fuel movement applicability for each unit in LCO 3.8.2 and LCO 3.7.11.

Although not a specific assumption of the safety analyses, this Specification requires that the DG automatically start, connect to the emergency bus, and automatically sequence the required loads. This capability in conjunction with the loss of voltage relays required OPERABLE by LCO 3.3.5, "Loss of Power (LOP) DG Start and Bus Separation Instrumentation," assures that a reliable source of AC power

BASES

APPLICABLE SAFETY ANALYSES (continued)

is promptly available in the event offsite power is lost. In addition, this capability provides automatic protection against degraded voltage conditions (via the degraded voltage sensing relays required OPERABLE in LCO 3.3.5) that could damage equipment required to maintain the unit in a safe shutdown condition. Therefore, the prompt availability of reliable backup emergency power provides additional assurance that the unit can be maintained in a safe shutdown condition in the event the grid becomes unstable.

Current requirements based on the decay time of the fuel prevent the movement of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). However, the Technical Specifications continue to address fuel movement involving recently irradiated fuel to support requirements for isolation or filtration that may be necessary to mitigate a fuel handling accident involving recently irradiated fuel. The retention of requirements within the Technical Specifications, in case the requirements are necessary to support fuel movement involving recently irradiated fuel, is consistent with the guidance of Reference 1.

In general, when the unit is shut down, 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, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 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.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required 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 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems - Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with the distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving irradiated fuel (Unit 1) and recently irradiated fuel (Unit 2)).

The qualified offsite circuit must be capable of maintaining nominal frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus(es). Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit.

During normal plant operation, electrical power for the onsite circuits comes from either the main generator through 22 kV to 4.36 kV unit station service transformers or from the two independent offsite 138 kV buses through 138 kV to 4.36 kV system station service transformers.

BASES

LCO (continued)

The secondary windings of the transformers are connected to four separate 4.16 kV normal buses, A, B, C, and D. Buses A and D provide power for the two redundant Class 1E 4.16 kV emergency buses AE and DF, respectively. During plant shutdown, the emergency buses receive power from the system station service transformers, or may receive power from the unit station service transformers by backfeeding the main transformer.

The DG must be capable of starting, accelerating to nominal speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. The 10 second timing requirement begins when the DG start signal is received by the DG start circuit and does not include the time it takes the instrumentation to detect a loss of voltage on the emergency busses. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby at ambient conditions.

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

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel or movement of fuel assemblies over irradiated fuel assemblies for Unit 1 (which includes recently irradiated fuel) and during movement of recently irradiated fuel assemblies or movement of fuel assemblies over recently irradiated fuel assemblies for Unit 2 provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core,

b. Systems needed to mitigate a fuel handling accident involving irradiated fuel (Unit 1) and recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours (Unit 2) are available,

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1

An offsite circuit would be considered inoperable if it were not available to the necessary portions of the electrical power distribution subsystem(s). One train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

A.2.1, A.2.2, A.2.3, A.2.4, A.2.5, B.1, B.2, B.3, B.4, and B.5

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation.

BASES

ACTIONS (continued)

Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or 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 unit 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 unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System's 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 are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized train.

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, 3, and 4. SR 3.8.1.7 is not required to be met since power is normally supplied by the offsite circuit. SR 3.8.1.12 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.15 is excepted because starting independence is not required with the DG(s) that is not required to be operable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by three Notes. The reason for Note 1 is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

Note 2 limits the scope of the requirement to verify the automatic load sequencing functions. The Note recognizes that the majority of equipment automatically sequenced on the emergency bus is not required to assure safe operation of the plant in shutdown MODES. The Note limits the verifications required by SR 3.8.1.13 and SR 3.8.1.14 to those loads required in the Applicable MODES of LCO 3.8.2. The required loads are the loads required OPERABLE by Technical Specifications and loads necessary to support the OPERABILITY of the loads required OPERABLE by Technical Specifications. Prior to entry into MODE 4, the verifications required by SR 3.8.1.13 and SR 3.8.1.14 must be complete for all loads required in MODES 1, 2, 3, and 4 in accordance with SR 3.0.4.

Note 3 clarifies the requirements of SR 3.8.1.14 such that only the DG response to the loss of offsite power must be verified to confirm OPERABILITY in the shutdown conditions addressed by LCO 3.8.2. No ESF (i.e., safety injection) actuation of the DG is required to be verified during the shutdown conditions addressed by LCO 3.8.2. Note 3 does not preclude the verification of ESF actuations and is only intended to clarify that an ESF actuation is not required to confirm DG or emergency bus OPERABILITY during the shutdown conditions addressed by LCO 3.8.2.

REFERENCES

1. NUREG-1431, "Standard Technical Specifications for Westinghouse Plants," Rev. 2, April 2001.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

A required Unit 2 diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that diesel for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand discussed in Reference 1. Unit 1's fuel oil requirement provides three and one-half days of inventory for the associated storage tank. The maximum load demand is calculated using the assumption one DG is operated at full load for 7 days. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from storage tank to day tank by either of two transfer pumps associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank to result in the loss of more than one DG. All outside tanks and piping are located underground.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by Reference 3. The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. The required lube oil inventory for each DG is sufficient to ensure 7 days of continuous operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has an air start system with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s). For Unit 1, the required air start capacity for each DG is met with two out of three air tanks in one of the two air banks at the specified air pressure. For Unit 2, one out of the two air banks (consisting of a single air tank) supplies sufficient volume at the specified pressure to meet the required capacity for each DG.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 4), and in Reference 5, assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation for Unit 2 DGs. Unit 1 DGs have a three and one-half day supply at a full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate at full load for the required days. This requirement, in conjunction with an ability to obtain replacement supplies within the required days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank and (engine mounted tank for Unit 1 only) fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air system is required to have a minimum capacity for five successive DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and the starting air subsystem 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 DG is required to be OPERABLE.

BASES

ACTIONS

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

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available for Unit 2. In this condition, the three and one-half day fuel oil supply for a DG is not available for Unit 1. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply for Unit 2 and a three day supply for Unit 1. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which 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 fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (≥ 6 days for Unit 2 and a three day supply for Unit 1), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

With lube oil inventory < 330 gal, sufficient lubricating oil to support 7 days of continuous DG 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. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (≥ 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3. 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),

BASES

ACTIONS (continued)

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, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 92 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

E.1

With starting air receiver pressure < 165 psig for Unit 1 and < 380 psig for Unit 2, sufficient capacity for five successive DG start attempts does not exist. However, as long as the receiver pressure is ≥ 125 psig for Unit 1 and ≥ 285 psig for Unit 2, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate usable inventory of fuel oil in the storage tanks to support a DG's operation for three and one-half days for Unit 1 and 7 days for Unit 2. This is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

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

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The required inventory for each DG is confirmed by verifying that a lube oil volume of 330 gallons (six 55 gallon oil drums) is available, in storage, for each DG. This required inventory is in addition to the lube oil in the DG sump required to maintain the manufacturer's recommended minimum sump level. If necessary to meet the required inventory, credit may be taken for lube oil in the DG sump above the manufacturer's recommended minimum sump level to supplement the required storage volume. The 330 gal requirement is based on the DG manufacturer consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG, when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer recommended minimum level.

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

SR 3.8.3.3

The tests of fuel oil prior to addition to the storage tanks (listed below) are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards for the tests identified in TS 5.5.9, “Diesel Fuel Oil Testing Program,” are as follows:

BASES

SURVEILLANCE REQUIREMENTS (continued)

a. Sample the new fuel oil in accordance with ASTM D4057-81 (Ref. 6),

b. Verify in accordance with the tests specified in ASTM D1298-80 (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 degrees and ≤ 39 degrees or an API gravity of within 0.3 degrees at 60°F, or a specific gravity of within 0.0016 at 60/60°F when compared to the supplier's certificate,

c. Verify in accordance with the tests specified in ASTM D975-81 (Ref. 6), a flash point of ≥ 125°F; and, if gravity was not determined by a comparison with the supplier's certification, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes;

d. Verify that the new fuel oil has water and sediment content of less than or equal to 0.05% when tested in accordance with ASTM D1796-83 (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 concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-81 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-81 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 (Ref. 6) or ASTM D2622-82 (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 DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-78, Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. Stored fuel oil volume is contained in more than one tank (i.e., day tanks and storage tanks); each tank is considered and tested separately.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished. The air receiver volume that ensures the required air start capacity is met, at the specified pressures, consists of the following:

For Unit 1, two out of three air tanks in one of the two air banks for each DG, and

For Unit 2, one out of the two air banks (consisting of a single air tank) for each DG.

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. 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 DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and 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. This SR is for preventative 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.

BASES

REFERENCES

1. UFSAR, Section 9.14.4 for Unit 1 and Section 9.5.4 for Unit 2.

2. Regulatory Guide 1.137.

3. UFSAR Section 9.14.6 for Unit 1 and UFSAR Section 9.5.4 for Unit 2.

4. UFSAR, Chapter 6.

5. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.

6. ASTM Standards: D4057-81, D1298-80, D975-81, D1796-83, D1552-79, D2622-82, and D2276-78, Method A.

7. ASTM Standards, D975-81, Table 1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred AC vital bus power (via inverters). As described by Reference 1, the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3) as addressed in the UFSAR.

The 125 VDC electrical power system consists of two independent and redundant safety related Class 1E DC electrical power subsystems (Train A and Train B). Each subsystem consists of two 125 VDC batteries (each battery 100% capacity for that portion of the subsystem), the associated battery charger(s) for each battery, and all the associated control equipment and interconnecting cabling.

For Unit 1, the required battery banks are Banks 1-1 and 1-3 on the orange bus and Banks 1-2 and 1-4 on the purple bus. The Unit 1 battery chargers are designated 1-1 and 1-3 on the orange bus and 1-2 and 1-4 on the purple bus. The Unit 1 battery chargers designated 1-1, 1-2, 1-3, and 1-4 are each comprised of two redundant chargers, designated as 1-1A and 1-1B, 1-2A and 1-2B, 1-3A and 1-3B and 1-4A and 1-4B. Each of these redundant chargers can supply the full range of required loads for the 125 VDC bus. Only one of the two redundant battery chargers associated with each battery bank is required to be operable.

The required Unit 2 battery banks are Banks 2-1 and 2-3 on the orange bus and Banks 2-2 and 2-4 on the purple bus. The Unit 2 battery chargers are designated 2-1 and 2-3 on the orange bus and 2-2 and 2-4 on the purple bus. In addition, for Unit 2, spare chargers (2–7 and 2-9) are also provided. Spare battery chargers 2-7 and 2-9 are each fully qualified as a substitute for a primary battery charger. For Unit 2, one safety switch is provided for each DC bus to provide a backup method for battery charging and bus supply if the primary charger is out of service. This is discussed in the UFSAR, Section 8.3.2.1 (Ref 4).

For Unit 1 and Unit 2, a spare charger that is fully qualified as described in the UFSAR and that meets applicable surveillance requirements, may be substituted as an operable charger.

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

BASES

BACKGROUND (continued)

The Train A and Train B DC electrical power subsystems provide the control power for its associated Class 1E AC power load group, 4.16 kV switchgear, and 480 V load centers. The DC electrical power subsystems also provide DC electrical power to the inverters, which in turn power the AC vital buses.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

Each 125 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 the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems, such as batteries, battery chargers, or distribution panels.

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in Reference 4. The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for Train A and Train B DC electrical power subsystems 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 each battery cell is 1.84 volts for batteries 1-1, 1-2, 2-1, 2-2, 2-3, and 2-4 and 1.864 volts for batteries 1-3 and 1-4.

Based on battery sizing calculations, a 5% design margin is maintained for the Enersys 2GN-13 model batteries (2-3 and 2-4) and a 2% design margin is maintained for the Enersys 2GN-21 model batteries (1-1, 1-2, 2-1, and 2-2). This margin is reserved for the batteries listed above in accordance with the battery vendor recommendations and NRC commitment in order to use the value of $\leq$ 2 amps float current to determine a fully charged battery (Ref. 9).

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 2.07 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Optimal long term performance, however, is obtained by maintaining a float voltage 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.25 Vpc corresponds to a total float voltage output of 135 V for a 60 cell battery as discussed in Reference 4.

BASES

BACKGROUND (continued)

Each Train A and Train B DC electrical power subsystem 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 battery charger also has sufficient excess capacity to restore the battery from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads discussed in Reference 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. 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 Reference 6, assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power and

b. A worst-case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The DC electrical power subsystems, each subsystem consisting of two batteries, battery charger for each battery and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE DC electrical power subsystem requires all required batteries and respective chargers to be operating and connected to the associated DC bus(es).

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

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

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

The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."

ACTIONS

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

Condition A represents one train with one or two battery chargers inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered time 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. The minimum established float voltage, measured at the battery terminals, is 2.13 volts per cell multiplied by the number of connected cells. The required number of connected cells is established in the battery sizing calculations (Ref. 10 through 17). The 2 hour limit 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

BASES

ACTIONS (continued)

reasonable 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 reasonable 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 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 capacity 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 72 hours. 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 72-hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE

BASES

ACTIONS (continued)

status. In addition, the 72-hour Completion Time takes into account the capacity and capability of the remaining DC sources, and the low probability of a DBA occurring during this period.

B.1

Condition B represents one train with one or two batteries inoperable. With one or two batteries inoperable, the DC bus is being supplied by the OPERABLE battery charger. Any event that results in a loss of the AC bus supporting the battery charger will also result in loss of DC to that train. Recovery of the AC bus, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., diesel generator control and field flash, AC load shed and diesel generator output circuit breakers, etc.) likely rely upon the batteries. In addition the energization transients of any DC loads that are beyond the capability of the battery charger and normally require the assistance of the batteries will not be able to be brought online. The 2 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific Completion Times.

C.1

Condition C represents one train with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

If one of the required DC electrical power subsystems is inoperable for reasons other than Condition A or B (e.g., inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst-case single failure could, however, result in the loss of minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 5 is consistent with the time recommended in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the 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 continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the 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, measured at the battery terminals, established by the battery manufacturer (i.e., 2.13 volts per cell multiplied by the number of connected cells). 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 the Surveillance Frequency Control Program.

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 8), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR provides two options. One option requires that each battery charger be capable of supplying 100 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 charger voltage requires a minimum output of 140 volts. The 4-hour time period is sufficient for the charger temperature to have stabilized. The minimum established float voltage, measured at the battery terminals, is 2.13 volts per cell multiplied by the number of connected cells.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest combined 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 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 $\leq$ 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 capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle of 2 hours, using actual or simulated emergency loads as specified in Reference 4.

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

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. Unit 1 UFSAR Appendix 1A, "1971 AEC General Design Criteria Conformance" and Unit 2 UFSAR Section 3.1, "Conformance with U. S. Nuclear Regulatory Commission General Design Criteria."

2. Safety Guide 6 (Unit 1) and Regulatory Guide 1.6, March 10, 1971 (Unit 2).

3. IEEE-308-1971 for Unit 1 and 1974 for Unit 2.

4. UFSAR, Chapter 8.

5. UFSAR, Chapter 6.

6. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.

7. Regulatory Guide 1.93, December 1974.

8. Regulatory Guide 1.32, February 1977.

9. NRC Regulatory Commitment documented in FENOC Letter L-06-162, "Supplement to License Amendment Request Nos. 296 and 169, Improved Standard Technical Specification Conversion," dated December 7, 2006.

10. 8700-E-201, DC System Management – BAT-1-1/BAT-CHG1-1.

11. 8700-E-202, DC System Management – BAT-1-2/BAT-CHG1-2.

12. 8700-E-203, DC System Management – BAT-1-3/BAT-CHG1-3.

13. 8700-E-204, DC System Management – BAT-1-4/BAT-CHG1-4.

14. 10080-E-201, DC System Management – BAT-2-1/BAT-CHG2-1.

15. 10080-E-202, DC System Management – BAT-2-2/BAT-CHG2-2.

16. 10080-E-203, DC System Management – BAT-2-3/BAT-CHG2-3.

17. 10080-E-204, DC System Management – BAT-2-4/BAT-CHG2-4.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Reference 2, assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies or movement of fuel assemblies over irradiated fuel assemblies for Unit 1 or movement of recently irradiated fuel assemblies or movement of fuel assemblies over recently irradiated fuel assemblies for Unit 2 ensure that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods,

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident involving handling irradiated fuel. For Unit 2 only, 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 100 hours. In future discussions, the term fuel assemblies will include "irradiated" and "recently irradiated" as applicable for each unit.

In general, when the unit is shut down, 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 DBAs that are

BASES

APPLICABLE SAFETY ANALYSES (continued)

analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6 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 DBAs 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).

LCO

The DC electrical power subsystem, the required subsystem consisting of two batteries, one battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train, is required to be OPERABLE to support one train of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems - Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling fuel).

BASES

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core,

b. Required features needed to mitigate a fuel handling accident involving handling fuel are available,

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

By allowing the option to declare required features inoperable with the associated DC power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO ACTIONS. In many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of fuel assemblies, and operations involving positive reactivity additions) that could result in loss of required shutdown margin (SDM) (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the Reactor Coolant System (RCS) for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining

BASES

ACTIONS (continued)

subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to 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 unit 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 subsystem should be completed as quickly as possible in order to minimize the time during which the unit 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 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND

This LCO delineates the limits on battery float current as well as electrolyte temperature, level, and float voltage for the DC power subsystem 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." In addition to the limitations of this Specification, the Battery Monitoring and Maintenance Program also implements a program specified in Specification 5.5.13 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead-Acid Batteries For Stationary Applications" (Ref. 3).

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 60 cell battery (i.e., cell voltage of 2.07 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Optimal long term performance, however, is obtained by maintaining a float voltage 2.25 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.25 Vpc corresponds to a total float voltage output of 135 V for a 60 cell battery as discussed in the UFSAR, Chapter 8 (Ref. 5).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Reference 2, assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one train of DC sources OPERABLE during accident conditions, in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power and

b. A worst-case single failure.

Battery parameters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.13.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery parameter limits are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With one or more cells in one or more batteries in one train < 2.07 V, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify "perform," a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered. If SR 3.8.6.1 is failed then there is not assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

B.1 and B.2

One or more batteries in one train with float current > 2 amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float

BASES

ACTIONS (continued)

voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addresses charger inoperability. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. 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 B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than 2.07 V, the associated "OR" statement in Condition F is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.07 V there is reasonable assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

A discharged battery with float voltage (the charger setpoint) across its terminals 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 reasonable assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 12 hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

BASES

ACTIONS (continued)

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

With one or more batteries in one train with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. In accordance with Required Action C.3, the minimum established design limits for electrolyte level (i.e., ≥ minimum level indication mark) must be re-established within 31 days. Condition C is modified by a Note that requires the completion of Required Action C.2 if the electrolyte level was found below the top of the plates. In this case, the visual inspection for leakage specified in Required Action C.2 must be performed prior to exiting Condition C even if the electrolyte level is restored to greater than or equal to the minimum established design limit.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.13, Battery Monitoring and Maintenance Program). They are modified by a Note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.13.b item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. The visual inspection and requirements of Specification 5.5.13.b are typically performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the batteries may have to be declared inoperable and the affected cells replaced.

D.1

With one or more batteries in one train with pilot cell temperature less than the minimum established design limit of 50°F, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

BASES

ACTIONS (continued)

E.1

With one or more batteries in redundant trains with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one train within 2 hours.

F.1

With one or more batteries with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, or E, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding battery must be declared inoperable. Additionally, discovering one or more batteries in one train with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 3). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 ACTION A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer. The minimum established float voltage, measured at the battery terminals, is 2.13 volts per cell multiplied by the number of connected cells. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.13. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 V. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.3

The limit specified for electrolyte level (i.e., ≥ minimum level indication mark) ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 50°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.6

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

It may consist of just two rates; for instance the one minute rate for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must 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 acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 3) and IEEE-485 (Ref. 4). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If the battery shows degradation, or if the battery has reached 85% of its expected life, the Surveillance Frequency is reduced to 18 months. Degradation is indicated, according to IEEE-450 (Ref. 3), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 3).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

BASES

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.
3. IEEE-450-1995.
4. IEEE-485-1983, June 1983.
5. UFSAR, Chapter 8 (Unit 2).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the vital buses. The inverters can be powered from an internal AC source/rectifier, a battery charger or from the station battery. The battery chargers have sufficient capacity to supply the required vital bus loads and may be used in lieu of the internal rectified AC source to power inverters. However, inverters with backup power available from the station battery provide the required uninterruptible power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in the UFSAR, Chapter 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 2) and Reference 3, assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required AC vital buses OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power and

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters (two per train) ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 4.16 kV safety buses are de-energized.

OPERABLE inverters require the associated vital bus to be powered by the inverter with output voltage within tolerances, and power input to the inverter from a 125 VDC station battery. Alternatively, power supply may be a battery charger or from an internal AC source via rectifier as long as the station battery is available as the uninterruptible power supply.

This LCO is modified by a Note that allows one inverter to be disconnected from a battery for ≤ 24 hours, if the vital bus is powered from a Class 1E constant voltage transformer or inverter using internal AC source during the period and all other inverters are OPERABLE. This allows an equalizing charge to be placed on one battery. Under certain conditions, if the inverters were not disconnected, the resulting voltage condition might damage the inverter. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 24 hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected AC vital bus while taking into consideration the time required to perform an equalizing charge on the battery bank.

The intent of this Note is to limit the number of inverters that may be disconnected. Only the inverter associated with the single battery undergoing an equalizing charge may be disconnected. All other inverters must be aligned to their associated batteries, regardless of the number of inverters or unit design.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

BASES

APPLICABILITY (continued)

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

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters - Shutdown."

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is re-energized from its Class 1E constant voltage source transformer or inverter using internal AC source or battery charger.

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC vital bus is powered from a source other than an inverter with battery backup, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices.

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of correct voltage output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC vital buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 8.

2. UFSAR, Chapter 6.

3. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters - Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Reference 2, assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum inverters to each AC vital bus during MODES 5 and 6 and during fuel movement ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods,

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident involving handling irradiated fuel or movement of fuel assemblies over irradiated fuel assemblies for Unit 1 or movement of recently irradiated fuel assemblies or movement of fuel assemblies over recently irradiated fuel assemblies for Unit 2. For Unit 2 only, due to radioactive decay, the inverters are 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 100 hours. In future discussions, the term fuel assemblies will include "irradiated" and "recently irradiated" as applicable for each unit.

In general, when the unit is shut down, 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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The rationale for this is based on the fact that many DBAs that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6 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 DBAs 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 inverters were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. The inverters with battery backup power provide uninterruptible supply of AC electrical power to the AC vital buses even if the 4.16 kV safety buses are de-energized. OPERABILITY of the inverters require that the AC vital bus be powered by the inverter. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling fuel).

BASES

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 and during movement of fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core,

b. Systems needed to mitigate a fuel handling accident involving handling fuel are available,

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

If two trains are required by LCO 3.8.10, "Distribution Systems - Shutdown," the remaining OPERABLE Inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of fuel assemblies, and operations involving positive reactivity additions) that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive

BASES

ACTIONS (continued)

reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a constant voltage source transformer.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of correct voltage output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems - Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and AC vital bus electrical power distribution systems are divided by train into two redundant and independent AC, DC, and AC vital bus electrical power distribution subsystems.

The AC electrical power subsystem for each train consists of a primary Engineered Safety Feature (ESF) 4.16 kV bus and secondary 480 V buses and load centers. Each 4.16 kV ESF bus has at least one separate and independent offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally connected to a unit source. After a loss of the unit power source to a 4.16 kV ESF bus, a transfer to the system offsite source is accomplished by utilizing a time delayed bus undervoltage relay. If all offsite sources are unavailable, the onsite emergency DG supplies power to the 4.16 kV ESF bus. Control power for the 4.16 kV ESF breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources - Operating," and the Bases for LCO 3.8.4, "DC Sources - Operating."

The secondary AC electrical power distribution subsystem for each train includes the safety related buses and load centers shown in Table B 3.8.9-1.

The 120 VAC vital buses are arranged in two load groups per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E constant voltage source transformers powered from the same train as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters - Operating." Each constant voltage source transformer is powered from a Class 1E AC bus.

The DC electrical power distribution subsystem consists of 125 V bus(es).

The list of all required DC and vital AC distribution buses is presented in Table B 3.8.9-1.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1), and in Reference 2, assume ESF systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power and

b. A worst case single failure.

The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or 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 load centers to be energized to their correct voltages. OPERABLE DC electrical power distribution subsystems require the associated buses and distribution panels to be energized to their correct voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their correct voltage from the associated inverter via inverted DC voltage, inverter using internal AC source, or Class 1E constant voltage transformer.

BASES

LCO (continued)

In addition, tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, that could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems - Shutdown."

ACTIONS

A.1

With one or more Train A and B required AC buses and load centers (except AC vital buses), in one train 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 ESF functions not being supported. Therefore, the required AC buses and load centers must be restored to OPERABLE status within 8 hours.

Condition A worst scenario is one train without AC power (i.e., no power from the unit and system station service transformers to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit

BASES

ACTIONS (continued)

operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of 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.

Required Action A.1 is modified by a Note that requires the applicable Conditions and Required Actions of LCO 3.8.4, "DC Sources - Operating," to be entered for DC trains made inoperable by inoperable power distribution subsystems. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. Inoperability of a distribution system can result in loss of charging power to batteries and eventual loss of DC power. This Note ensures that the appropriate attention is given to restoring charging power to batteries, if necessary, after loss of distribution systems.

BASES

ACTIONS (continued)

B.1

With one or more AC vital buses inoperable, and a loss of function has not yet occurred, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC, inverter using internal AC source, or Class 1E constant voltage transformer.

Condition B represents one or more AC vital buses without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital buses and restoring power to the affected vital bus.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue,

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train, and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the vital bus distribution system. At this time, an AC train could again become inoperable, and vital bus distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With one or more DC buses inoperable, and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one or more DC buses without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

BASES

ACTIONS (continued)

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue,

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train, and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3). The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

E.1

Condition E 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 inoperable electrical power distribution subsystem results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of correct 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 for Unit 1 and Chapter 15 for Unit 2.

3. Regulatory Guide 1.93, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

		Unit 1 Only		Unit 2 Only	
		(Orange)	(Purple)	(Orange)	(Purple)
TYPE	VOLTAGE	TRAIN A*	TRAIN B*	TRAIN A*	TRAIN B*
AC emergency buses	4160 V	1AE	1DF	2AE	2DF
	480 V	1N	1P	2N	2P
DC buses	125 V	1-1	1-2	2-1	2-2
		1-3	1-4	2-3	2-4
AC vital buses	120 V	I	II	I	II
		III	IV	III	IV

*Each train of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of the AC, DC, and AC vital bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Reference 2, assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies or movement of fuel assemblies over irradiated fuel assemblies for Unit 1 or movement of recently irradiated fuel assemblies or movement of fuel assemblies over recently irradiated fuel assemblies for Unit 2 ensure that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods,

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident involving handling irradiated fuel (Unit 1). For Unit 2 only, 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 100 hours). In future discussions, the term fuel assemblies will include "irradiated" and "recently irradiated" as applicable for each unit.

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

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 required systems, equipment, and components - all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling fuel).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core,

b. Systems needed to mitigate a fuel handling accident involving handling fuel are available,

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

The AC, DC, and AC vital bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

BASES

ACTIONS (continued)

A.1, A.2.1, A.2.2, A.2.3, A.2.4, A.2.5, and A.2.6

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and 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. 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 fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.5 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.6 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR 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 unit safety systems may be without power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution subsystems are functioning properly, with all the required buses energized. The verification of correct 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 for Unit 1 and Chapter 15 for Unit 2.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. Plant procedures ensure the specified boron concentration maintains an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed from the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank through the open reactor vessel by gravity feeding or by the use of the Low Head Safety Injection System pumps.

The pumping action of the Residual Heat Removal (RHR) System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation during refueling (see LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

BASES

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is controlled by isolating unborated water sources and maintaining the required refueling boron concentration in the RCS. The boron concentration specified in the COLR for MODE 6 is an operating restriction necessary to maintain at least a 5% Δk/k margin of safety during refueling. The resulting core reactivity is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain $\leq$ 0.95 during the refueling operation. Hence, at least a 5% Δk/k margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of $\leq$ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

The Applicability is modified by a Note. The Note states that the limits on boron concentration are only applicable to the refueling canal and the refueling cavity when those volumes are connected (hydraulically coupled) to the RCS. When the refueling canal and the refueling cavity are isolated from the RCS, no potential path for boron dilution exists.

BASES

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling canal, or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position. Operations that individually add limited positive reactivity (e.g. temperature fluctuations from inventory addition or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

A.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the RCS, and connected portions of the refueling canal and the refueling cavity, is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical analysis. Prior to reconnecting portions of the refueling canal or the refueling cavity to the RCS, this SR must be met per SR 3.0.1. If any dilution activity has occurred while the cavity or canal were disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

REFERENCES

1. Unit 1 UFSAR, Appendix 1A, "1971 AEC General Design Criteria Conformance." Unit 2 UFSAR, Section 3.1, "Conformance with NRC General Design Criteria."

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND	The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed or primary source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core. The primary source range neutron flux monitors are boron-based detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux (1E+6 cps). The detectors also provide continuous visual indication in the control room. The NIS is designed in accordance with the criteria presented in Reference 1. In addition to the primary source range monitors described above, alternate source range monitors may be used to meet the LCO requirement. The alternate monitors may be either installed spare detectors or portable monitors with sufficient sensitivity to adequately monitor reactivity changes in the core during refueling operations.
APPLICABLE SAFETY ANALYSES	Two OPERABLE source range neutron flux monitors (primary or alternate) are required to provide a signal to alert the operator to unexpected changes in core reactivity such as an improperly loaded fuel assembly. The Technical Specifications require that unborated water sources be isolated in MODES 4, 5, and 6. The requirement to isolate unborated water sources is considered to preclude a boron dilution accident. Therefore, no boron dilution accident analysis is necessary for these MODES. The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. The LCO may be met by using any combination of primary or alternate source range monitors. To be OPERABLE, each monitor must provide continuous visual indication in the control room.

BASES

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, the primary source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." In addition, one source range detector is required to be OPERABLE in MODES 3, 4, and 5 when all rods are fully inserted and without rod withdrawal capability by LCO 3.3.8, "Boron Dilution Detection Instrumentation."

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1 must be suspended immediately. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that which would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made (as specified in Required Actions A.1 and A.2), the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

BASES

ACTIONS (continued)

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

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

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Unit 1 and Unit 2 UFSAR Section 7.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During movement of fuel involving recently irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, restricting the release of radioactivity from containment is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained within the requirements of 10 CFR 50.67. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During movement of fuel involving recently irradiated fuel assemblies within containment, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During movement of recently irradiated fuel assemblies or the movement of fuel assemblies over recently irradiated fuel assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed.

BASES

BACKGROUND (continued)

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted to within regulatory limits.

The Containment Purge and Exhaust System includes a 42 inch purge penetration and a 42 inch exhaust penetration. During MODES 1, 2, 3, and 4, the two valves in each of the purge and exhaust penetrations are secured in the closed position. The Containment Purge and Exhaust System is not subject to a Specification in MODE 5.

In MODE 6, the Containment Purge and Exhaust System is used for containment ventilation.

The radiation monitors associated with the Unit 1 Containment Purge and Exhaust System are not mounted in a seismically qualified ventilation duct. Therefore, Unit 1 can not credit containment isolation when necessary to mitigate the radiological consequences of a design bases fuel handling accident. Unit 1 must rely on filtration of the purge exhaust by an OPERABLE Supplemental Leak Collection and Release System (SLCRS) filter train.

The Unit 2 Containment Purge and Exhaust System credits containment isolation when necessary to mitigate the radiological consequences of a design bases fuel handling accident. The limit placed on the containment purge and exhaust flow (7500 cfm) ensures the Unit 2 purge and exhaust isolation valves close before any radioactivity is released from containment.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Functionally equivalent isolation methods must be approved by an engineering evaluation and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during recently irradiated fuel movements and the movement of fuel assemblies over recently irradiated fuel assemblies (Reference 1).

BASES

APPLICABLE SAFETY ANALYSES

During refueling operations, the postulated event that results in the most severe radiological consequences is a fuel handling accident (Ref. 2). The limiting fuel handling accident analyzed in Reference 2, includes dropping a single irradiated fuel assembly and handling tool (conservatively estimated at 2500 pounds) directly onto another irradiated fuel assembly resulting in both assemblies being damaged. The analysis assumes a 100 hour decay time prior to moving irradiated fuel.

The applicable limits for offsite and control room dose from a fuel handling accident are specified in 10 CFR 50.67. Standard Review Plan, Section 15.0.1, Rev 0 (Ref. 3) provides an additional offsite dose criteria of 6.3 rem total effective dose equivalent (TEDE) for fuel handling accidents.

The water level requirements of LCO 3.9.6, "Refueling Cavity Water Level," in conjunction with a minimum decay time of 100 hours prior to irradiated fuel movement, ensure that the resulting offsite and control room dose from the limiting fuel handling accident is within the limits required by 10 CFR 50.67 and within the acceptance criteria of Reference 3 without the need for containment closure.

Therefore, the containment closure requirements of LCO 3.9.3, "Containment Penetrations," are only applicable during refueling operations involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). Current requirements based on the decay time of the fuel prevent the movement of recently irradiated fuel. However, the requirements for containment closure are retained in the Technical Specifications in case these requirements are necessary to support fuel movement involving recently irradiated fuel consistent with the guidance of Reference 4.

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO limits the consequences of a fuel handling accident involving handling recently irradiated fuel in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge and exhaust penetrations which may be open if the exhaust airflow is lined up to an OPERABLE SLCRS train (Unit 1) or capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System (Unit 2).

For Unit 2, an OPERABLE Containment Purge and Exhaust Isolation System includes purge and exhaust valves that isolate within the required time and a purge exhaust flow that is within the required limit. The Unit 2

BASES

LCO (continued)

purge and exhaust valve isolation time and purge exhaust flow requirements provide assurance that, in the event of a limiting fuel handling accident, the purge and exhaust penetrations will be isolated prior to the resulting radioactivity being released from containment.

For the OPERABLE containment purge and exhaust penetrations for Unit 2, this LCO ensures that these penetrations are isolable by the Containment Purge and Exhaust Isolation System and for Unit 1 that the purge exhaust is lined up to an OPERABLE SLCRS train when moving recently irradiated fuel and during movement of fuel assemblies over recently irradiated fuel assemblies. The OPERABILITY requirements for this LCO ensure that the Unit 2 automatic purge and exhaust valve closure times specified in the Licensing Requirements Manual (LRM) can be achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves are prevented, or for Unit 1, that the releases are filtered such that radiological doses are within the acceptance limit.

APPLICABILITY

The containment penetration requirements are applicable during movement of recently irradiated fuel assemblies or the movement of fuel assemblies over recently irradiated fuel assemblies within containment because this is when there is a potential for the limiting fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1, "Containment Operability" and LCO 3.6.3, "Containment Isolation Valves." In MODES 5 and 6, when movement of irradiated fuel assemblies within containment is not being conducted, the potential for a fuel handling accident does not exist. Additionally, due to radioactive decay, a fuel handling accident that does not involve recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) will result in doses that are well within the guideline values specified in 10 CFR 50.67 even without containment closure capability. Therefore, under these conditions no requirements are placed on containment penetration status.

Although movement of recently irradiated fuel is not currently permitted, the requirements for containment closure are retained in the Technical Specifications in case these requirements are necessary to support fuel movement involving recently irradiated fuel consistent with the guidance of Reference 4.

BASES

ACTIONS

A.1 and A.2

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Unit 2 Containment Purge and Exhaust Isolation System not capable of automatic actuation when the purge and exhaust valves are open or the Unit 1 purge exhaust not lined up to an OPERABLE SLCRS train, the unit must be placed in a condition where the isolation or filtration function is not needed. This is accomplished by immediately suspending movement of recently irradiated fuel assemblies and the movement of any fuel assemblies over recently irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

The Surveillance requires that the Unit 2 containment purge exhaust flow rate be verified to be ≤ 7500 cfm. The Surveillance is necessary to verify the Containment Purge and Exhaust Isolation System is OPERABLE. LCO 3.9.3.c.2 requires that the containment purge and exhaust penetrations are capable of being isolated by an OPERABLE Containment Purge and Exhaust Isolation System. Verifying the purge exhaust flow is within the limit provides assurance that, in the event of a limiting fuel handling accident, the purge and exhaust penetrations will be isolated prior to the resulting radioactivity being released from containment.

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

The Surveillance is modified by two Notes that specify the Surveillance is only applicable to Unit 2 and that the Surveillance is only required to be met when the containment purge and exhaust is operating in accordance with LCO 3.9.3.c.2. The Surveillance is only applicable to Unit 2 because Unit 1 does not credit purge and exhaust isolation and instead relies on filtration of the purge exhaust flow.

SR 3.9.3.2

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open Unit 2 purge and exhaust valves will demonstrate that the

BASES

SURVEILLANCE REQUIREMENTS (continued)

valves are not blocked from closing and that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge and exhaust isolation signal. The Surveillance on the open Unit 1 purge and exhaust valves will confirm that the purge exhaust is lined up to an OPERABLE SLCRS filtration train.

This Surveillance ensures that a postulated fuel handling accident involving handling recently irradiated fuel that releases fission product radioactivity within the containment will not result in a release of significant fission product radioactivity to the environment in excess of those recommended by Standard Review Plan Section 15.0.1 (Reference 3). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.3.3

This Surveillance demonstrates that each Unit 2 containment purge and exhaust valve actuates to its isolation position on manual initiation and on an actual or simulated high radiation signal. The Frequency maintains consistency with other similar ESFAS instrumentation and valve testing requirements that ensure the valves are capable of closing after a postulated fuel handling accident involving handling recently irradiated fuel to limit a release of fission product radioactivity from the containment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by two Notes stating that this Surveillance is only applicable to Unit 2 and that this Surveillance is not required to be met for valves in isolated penetrations. The LCO provides the option to close penetrations in lieu of requiring automatic actuation capability. The Surveillance is not applicable to Unit 1 because Unit 1 does not credit purge and exhaust isolation and relies on filtration instead.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.3.4

The Surveillance requires that the Unit 2 containment purge and exhaust valve isolation time be verified within the limit. The required isolation time for the containment purge and exhaust valves is specified in the LRM. The Surveillance is necessary to verify the Containment Purge and Exhaust Isolation System is OPERABLE. LCO 3.9.3.c.2 requires that the containment purge and exhaust penetrations are capable of being isolated by an OPERABLE Containment Purge and Exhaust Isolation System. Verifying the purge and exhaust valve isolation time is within the limit provides assurance that, in the event of a limiting fuel handling accident, the purge and exhaust penetrations will be isolated prior to the resulting radioactivity being released from containment.

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

The Surveillance is modified by two Notes that specify the Surveillance is only applicable to Unit 2 and that the Surveillance is only required to be met when the containment purge and exhaust is operating in accordance with LCO 3.9.3.c.2. The Surveillance is only applicable to Unit 2 because Unit 1 does not credit purge and exhaust isolation and instead relies on filtration of the purge exhaust flow.

REFERENCES

1. GPU Nuclear Safety Evaluation SE-0002000-001, Rev. 0, May 20, 1988.

2. UFSAR, Section 14.2.1 (Unit 1) and UFSAR, Section 15.7.4 (Unit 2).

3. NUREG-0800, Section 15.0.1, Rev. 0, July 2000.

4. NUREG-1431, "Standard Technical Specifications for Westinghouse Plants," Rev. 2, April 2001.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit the RHR pump to be removed from operation for short durations, under the condition that the boron concentration is not diluted. This conditional stopping of the RHR pump does not result in a challenge to the fission product barrier.

The RHR System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation to provide:

a. Removal of decay heat,

b. Mixing of borated coolant to minimize the possibility of criticality, and

c. Indication of reactor coolant temperature.

BASES

LCO (continued)

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the RCS temperature. The normal recirculation flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

The LCO is modified by two Notes. Notes 1 and 2 allow the required operating RHR loop to be removed from operation for up to 1 hour per 8 hour period or up to 4 hours per 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration by the introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1. Boron concentration reduction with coolant at boron concentrations less than required to assure the RCS boron concentration is maintained is prohibited because uniform concentration distribution cannot be ensured without forced circulation. The one hour allowance permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. The four hour allowance is used solely for the performance of ultrasonic inservice inspection inside the reactor vessel nozzles. During the time the RHR is not in operation, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.6, "Refueling Cavity Water Level." Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Notes to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the

BASES

ACTIONS (continued)

RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4, A.5, A.6.1, and A.6.2

If no RHR is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with four bolts,

b. One door in each installed air lock must be closed, and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System. The safety function of the Containment Purge and Exhaust Isolation System required for OPERABILITY of the system in order to satisfy Action A.6.2 consists of the capability to close at least one isolation valve in each penetration by either automatic actuation on high radiation or manually from the control room.

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

BASES

ACTIONS (continued)

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance verifies that the RHR loop is circulating reactor coolant at the specified flow rate of ≥ 3,000 gpm. The verification of the specified flow rate provides additional assurance of adequate forced circulation and mixing of the RCS during operations involving the addition of coolant into the RCS with a boron concentration that is less than required to maintain the required SHUTDOWN MARGIN.

The Surveillance is modified by a Note that specifies the conditions under which the Surveillance is required to be met. The Note states that the Surveillance is only required to be met prior to the start of (i.e., within an hour before) and during operations that cause the introduction of coolant into the RCS with boron concentration less than that required to meet the minimum required boron concentration of LCO 3.9.1. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.4.2

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal and to prevent thermal and boron stratification in the core. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Unit 1 UFSAR, Appendix 1A, "1971 AEC General Design Criteria Conformance." Unit 2 UFSAR, Section 3.1, "Conformance with NRC General Design Criteria."

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge.

The RHR System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE. Additionally, one loop of RHR must be in operation in order to provide:

a. Removal of decay heat,

b. Mixing of borated coolant to minimize the possibility of criticality, and

c. Indication of reactor coolant temperature.

This LCO is modified by two Notes. Note 1 permits the RHR pumps to be removed from operation for ≤ 15 minutes when switching from one train to another.

BASES

LCO (continued)

The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and the core outlet temperature is maintained > 10 degrees F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of 2 hours provided the other loop is OPERABLE and in operation. Prior to declaring the loop inoperable, consideration should be given to the existing plant configuration. This consideration should include that the core time to boil is short, there is no draining operation to further reduce RCS water level and that the capability exists to inject borated water into the reactor vessel. This permits surveillance tests to be performed on the inoperable loop during a time when these tests are safe and possible.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the RCS temperature. The normal recirculation flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

Both RHR pumps may be aligned to the refueling water storage tank to support draining the refueling cavity or for performance of required testing.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level."

BASES

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.4, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3, B.4, B.5.1, and B.5.2

If no RHR is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with four bolts,

b. One door in each installed air lock must be closed, and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System. The safety function of the Containment Purge and Exhaust Isolation System required for OPERABILITY of the system in order to satisfy

BASES

LCO (continued)

Action B.5.2 consists of the capability to close at least one isolation valve in each penetration by either automatic actuation on high radiation or manually from the control room.

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions stated above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance verifies that the RHR loop is circulating reactor coolant at the specified flow rate of ≥ 3,000 gpm. The verification of the specified flow rate provides additional assurance of adequate forced circulation and mixing of the RCS during operations involving the addition of coolant into the RCS with a boron concentration that is less than required to maintain the required SHUTDOWN MARGIN.

The Surveillance is modified by a Note that specifies the conditions under which the Surveillance is required to be met. The Note states that the Surveillance is only required to be met prior to the start of (i.e., within an hour before) and during operations that cause the introduction of coolant into the RCS with boron concentration less than that required to meet the minimum required boron concentration of LCO 3.9.1. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.2

This Surveillance verifies that the RHR loop is circulating reactor coolant at the specified flow rate of ≥ 1,000 gpm. The verification of the specified flow rate provides additional assurance of adequate forced circulation of the RCS when the RCS water level is more than three feet below the reactor vessel flange.

The Surveillance is modified by a Note that specifies the conditions under which the Surveillance is required to be met. The Note states that the Surveillance is only required to be met when RCS water level is > three

BASES

SURVEILLANCE REQUIREMENTS (continued)

feet below the reactor vessel flange. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.3

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal and to prevent thermal and boron stratification in the core. In addition, during operation of the RHR loop with the water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.4

Verification that the required pump is OPERABLE ensures that an additional RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES

1. Unit 1 UFSAR, Appendix 1A, "1971 AEC General Design Criteria Conformance." Unit 2 UFSAR, Section 3.1, "Conformance with NRC General Design Criteria."

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Cavity Water Level

BASES

BACKGROUND	The movement of irradiated fuel assemblies or the movement of any fuel assemblies over irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the refueling canal, fuel transfer canal, and refueling cavity. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses and the control room dose from the accident to within the limits of 10 CFR 50.67 (Ref. 4), as provided by the guidance of Reference 3.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies or the movement of any fuel assemblies over irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.183 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 (Appendix B of Ref. 1) to be used in the accident analysis for iodine. The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 100 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses and the control room dose are maintained within allowable limits (Refs. 2 and 4). Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as provided by the guidance of References 3 and 4.

BASES

APPLICABILITY

LCO 3.9.6 is applicable when moving irradiated fuel assemblies or when moving any fuel assemblies over irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.15, "Fuel Storage Pool Water Level."

ACTIONS

A.1 and A.2

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving moving irradiated fuel assemblies or moving fuel assemblies over irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement 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 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

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

REFERENCES

1. Regulatory Guide 1.183, July 2000.

2. UFSAR, Section 14.2.1 (Unit 1) and
UFSAR, Section 15.7.4 (Unit 2).

3. NUREG-0800, Section 15.0.1.

4. 10 CFR 50.67.