TECHNICAL SPECIFICATIONS BASES

FOR NORTH ANNA UNITS 1 & 2

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B 2.1 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. The maximum fuel centerline temperatures are given by the best-estimate relationships defined in SL 2.1.1.2 and are dependent upon whether the Westinghouse or Framatome fuel is evaluated. 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

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BASES

BACKGROUND (continued)

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 prevents violation of the reactor core SLs.

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 allowable values (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and flow, AFD, 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 main steam safety valves.

The SLs represent a design requirement for establishing the RPS trip allowable values identified previously (as indicated in the UFSAR, Ref. 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

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BASES

SAFETY LIMITS (continued)

melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the 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.

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 that the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS and main steam safety valves ensures that for variations in the THERMAL POWER, RCS pressure, RCS average temperature, RCS flow rate, and AFD 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 main steam safety valves 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. Allowable values for the reactor trip functions are specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

BASES

SAFETY LIMIT VIOLATIONS	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. UFSAR, Section 3.1.6. 2. UFSAR, Section 7.2.

B 2.1 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 during operating conditions, the continued integrity of the RCS is ensured. According to 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 (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.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

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

The Reactor Trip System allowable values (Ref. 5), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressure trip allowable value is specifically determined 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 the following:

a. Pressurizer power operated relief valves (PORVs);

b. Steam Generator PORVs;

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 RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowed in the RCS piping, valves, and fittings under USAS, Section B31.1 (Ref. 6) is 120% of design pressure. The most limiting of these two allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2735 psig.

BASES

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.

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 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. UFSAR, Sections 3.1.10, 3.1.11, and 3.1.24.

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. USAS B31.1, Standard Code for Pressure Piping, American Society of Mechanical Engineers, 1967.

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B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.9 establish the general requirements applicable to all Specifications 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

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BASES

LCO 3.0.2 (continued)

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.

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.

BASES

LCO 3.0.3

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

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

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 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 unit 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.

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BASES

LCO 3.0.3 (continued)

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.

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 Specification 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 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 3.7.16, "Fuel Storage Pool Water Level." LCO 3.7.16 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO

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BASES

LCO 3.0.3 (continued)

can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.16 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 Action of LCO 3.7.16 of "Suspend movement of irradiated fuel assemblies in the fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It precludes placing the unit in a MODE or other specified condition stated in that Applicability (e.g., Applicability desired to be entered) when the following exist:

a. Unit conditions are such that the requirements of the LCO would not be met in the Applicability desired to be entered; and

b. Continued noncompliance with the LCO requirements, if the Applicability were entered, would result in the unit being required to exit the Applicability desired to be entered to comply with the Required Actions.

Compliance 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.

When an LCO is not met, LCO 3.0.4 also allows entering MODES or other specified conditions in the Applicability following assessment of the risk impact and determination that the impact can be managed. The risk evaluation may use quantitative, qualitative, or blended approaches, and the risk evaluation 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 evaluations will be conducted using the procedures and

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BASES

LCO 3.0.4 (continued)

guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants."

The results of the risk evaluation shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. Consideration will 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.

A risk assessment and establishment of risk management actions, as appropriate, are required for determination of acceptable risk for entering MODES or other specified conditions in the Applicability when an LCO is not met. The elements of the risk assessment and risk management actions are included in Regulatory Guide 1.182 which addresses general guidance for conduct of the risk evaluation, 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.

A quantitative, qualitative, or blended risk evaluation must be performed to assess the risk impact of entering the MODE or other specified condition in the Applicability, based on the specific plant configuration at that time and the risk impacts must be managed in accordance with the assessment results.

From generic evaluations, systems/components can be identified which are equally or more important to risk in MODE 1 than in the transition MODES. The Technical Specifications allow continued operation with this equipment unavailable during MODE 1 operation for the duration of the Completion Time. Since this is allowable, and since the risk impact bounds the risk of transitioning up in MODE and entering the Conditions and Required Actions, the use of the LCO 3.0.4 allowance for these systems should be generally acceptable, as long as the risk is assessed and managed as

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BASES

LCO 3.0.4 (continued)

stated above. However, there is a small subset of systems/components that have been generically determined to be more important to risk in MODES 2-5 and do not have the LCO 3.0.4 allowance. These system/components are listed below.

The Applicability should be reviewed with respect to the actual plant configuration at that time. Each individual application of LCO 3.0.4.b, whether due to one or more than one LCO 3.0.4.b allowance at the same time, is required to be evaluated under the auspices of 10 CFR 50.65(a)(4) and consideration of risk management actions discussed in Regulatory Guide 1.182. For those cases where the risk of the MODE change may be greater (i.e., the systems and components listed below), prior NRC review and approval of a specific LCO 3.0.4 allowance is required.

The LCO 3.0.4.b allowance typically only applies to systems and components. The values and parameters of the Technical Specifications (e.g., Containment Air Temperature, Containment Pressure, Moderator Temperature Coefficient, etc.) are typically not addressed by this LCO 3.0.4.b allowance. These values and parameters are addressed by the LCO 3.0.4.c allowance.

A list of the LCO 3.0.4.c specific value and parameter allowances approved by the NRC is provided below.

LCO 3.4.16, RCS Specific Activity

In order to support the conduct of the appropriate assessments, each Owners Group has performed an evaluation to identify plant systems or components which are more important to risk in the transition MODES than in MODE 1. To apply the LCO 3.0.4 allowance to these systems and components, prior NRC review and approval is required. These systems are listed in the following table.

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BASES

LCO 3.0.4 (continued)

System*	MODE or Other Specified Condition in the Applicability
RCS Loops (RHR)	5
LTOP System	4, 5
ECCS Shutdown (ECCS High Head Subsystem)	4
AFW System	1
AC Sources (Diesel Generators)	1, 2, 3, 4, 5, 6

* Including systems supporting the OPERABILITY of the listed systems.

NUMARC 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," states that the rigor of the risk analysis should be commensurate with the risk impact of the proposed configuration. For unavailable plant systems or components listed on the above table, a plant MODE change has been determined, through generic evaluation, to result in a potential risk increase. Therefore, prior NRC review and approval is required to apply the LCO 3.0.4 allowance to these systems and components.

For unavailable plant systems or components not appearing in the above table, proposed plant MODE changes will generally not involve a risk increase greater than the system or component being unavailable in MODE 1. The risk assessment performed to support use of LCO 3.0.4.b for systems or components not appearing on the above table must meet all considerations of NUMARC 93-01, but need not be documented.

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

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

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BASES

LCO 3.0.4 (continued)

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

LCO 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4, MODE 2 from MODE 3, or MODE 1 from MODE 2. Furthermore, LCO 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODES 1, 2, 3, or 4. The requirements of LCO 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODES 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

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, changing MODES or other specified conditions while in an ACTIONS Condition, in compliance with LCO 3.0.4, is not a violation of SR 3.0.1 or SR 3.0.4 for those Surveillances that do not have to be performed due to the associated inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

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

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

b. The OPERABILITY of other equipment.

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BASES

LCO 3.0.5 (continued)

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

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

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

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system 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

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BASES

LCO 3.0.6 (continued)

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

Cross 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; or (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; or (EXAMPLE B 3.0.6-2)

(continued)

BASES

LCO 3.0.6 (continued)

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)

EXAMPLE B 3.0.6-1

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.

EXAMPLE B 3.0.6-2

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.

EXAMPLE B 3.0.6-3

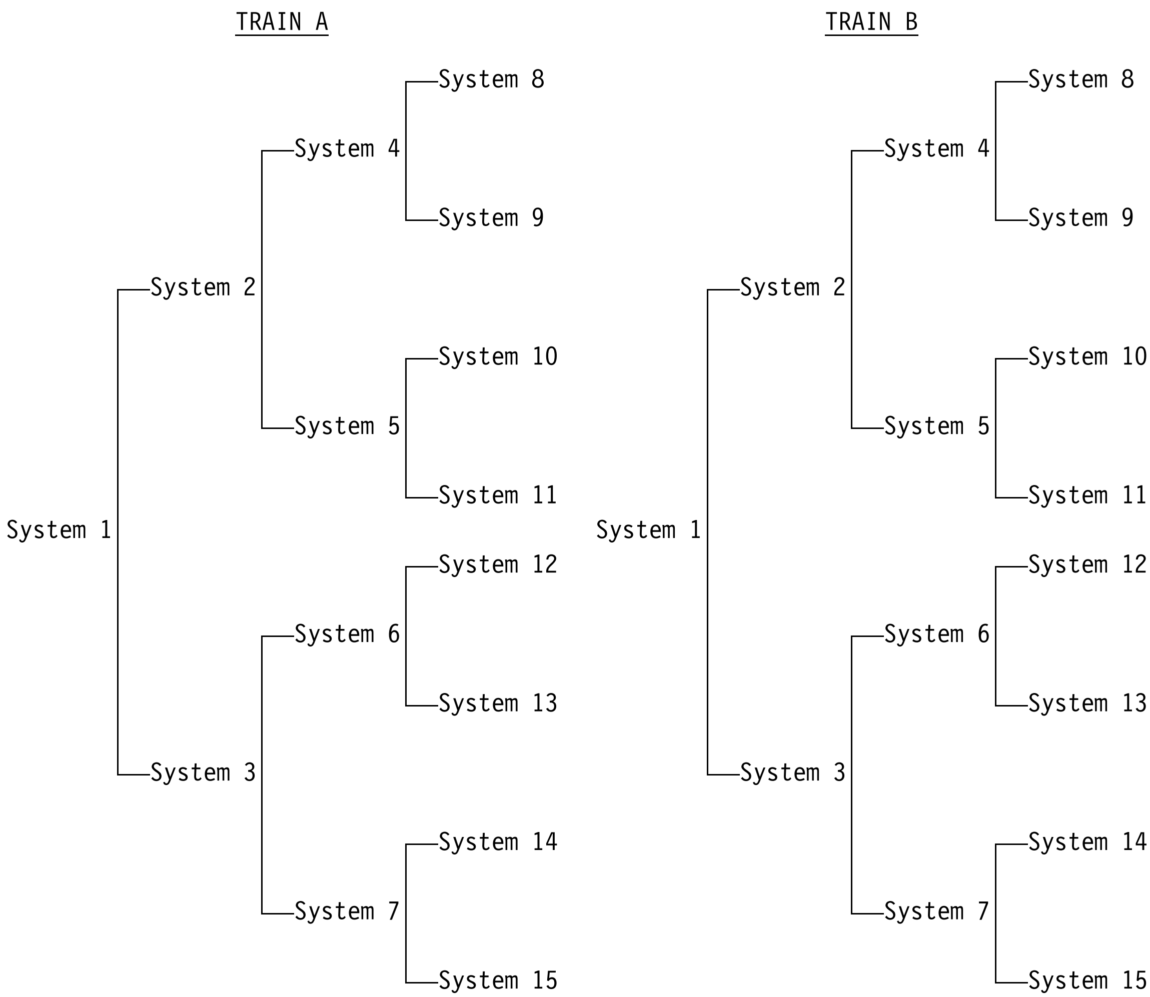
If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

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.

(continued)

BASES

LCO 3.0.6
(continued)



(continued)

BASES

LCO 3.0.6 (continued)

This loss of safety function does not require consideration of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the ACTIONS of the support system, this accounts for any temporary loss of redundancy or single failure protection. 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 a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the 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.

(continued)

BASES

LCO 3.0.7 (continued)

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.

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.

(continued)

BASES

LCO 3.0.8 (continued)

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.

In order to use LCO 3.0.8 for an inoperable snubber(s) the following conditions required by the NRC must be satisfied:

- When applying LCO 3.0.8.a, at least one train of Auxiliary Feedwater (AFW) System must be OPERABLE during MODES when AFW is required to be OPERABLE. When applying LCO 3.0.8.a during MODES when AFW is not required to be OPERABLE, at least one train of the mode specific credited core cooling method (i.e., Residual Heat Removal System) must be OPERABLE. Reliance on the availability of credited core cooling source during modes where AFW is not required to be OPERABLE, provides an equivalent safety margin for plant operations and meets the intent of Technical Specification Task Force (TSTF) 372.
- When applying LCO 3.0.8.b, at least one AFW train (including a minimum set of supporting equipment required for its successful operation) not associated with the inoperable snubber(s) shall be OPERABLE, 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.
- Confirm that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. LCO 3.0.8 does not apply to non-seismic snubbers.

In addition, 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 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

LCO 3.0.9

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

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

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

This provision can be applied to barriers that protect against the initiating events listed below. The provision can not be applied to the TS ventilation systems since specific Conditions are provided for an inoperable barrier. The provision cannot be applied to a fire barrier. However, if the barrier performs multiple functions (e.g., fire and HELB) and if the fire barrier program requirements can be satisfied then LCO 3.0.9 can be applied to the barrier for the HELB function. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

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

- Loss of coolant accidents;

(continued)

BASES

LCO 3.0.9 (continued)

- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.182, "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." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

The resultant risk management actions may impose time limits for barrier removal. In addition, other considerations, such as the administrative provisions for controlling fire barriers and the plant technical specifications, may place limitations on continued reactor operation with a hazard barrier removed. It may be possible to take compensatory measures to maintain SSC operability and avoid entering the technical specifications action statement for shutting down the reactor (e.g., installing a temporary barrier that provides equivalent protection or establishing administrative controls). Also, if the hazard does not exist at the time, the SSC would remain operable.

LCO 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their

(continued)

BASES

LCO 3.0.9 (continued)

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

If during the time that LCO 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

BASES

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.

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 (include 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.

(continued)

BASES

SR 3.0.1 (continued)

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

Upon completion of maintenance, appropriate post 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.

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 unit 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 requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is the Containment Leakage Rate Testing

(continued)

BASES

SR 3.0.2 (continued)

Program. This program establishes testing requirements and Frequencies in accordance with the requirements of 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

(continued)

BASES

SR 3.0.3 (continued)

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 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 to perform the Surveillance 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

(continued)

BASES

SR 3.0.3 (continued)

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

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

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

SR 3.0.4

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

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or component 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:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specific condition in the Applicability for an unlimited period of time,

(continued)

BASES

SR 3.0.4 (continued)

b. After performance of a risk evaluation, consideration of the results, determination of the acceptability of the MODE change, and establishment of risk management actions, if appropriate, or

c. When a specific value or parameter allowance has been approved by the NRC.

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.

The provisions of SR 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.

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

(continued)

BASES

SR 3.0.4 (continued)

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.

SR 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4, MODE 2 from MODE 3, or MODE 1 from MODE 2. Furthermore, SR 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODES 1, 2, 3, or 4. The requirements of SR 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODES 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be independent and one must be 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 Rod Control 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 Rod Control 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 $\leq$ 225 cal/gm energy deposition to unirradiated fuel and $\leq$ 200 cal/gm energy deposition to irradiated fuel for the rod ejection accident); and

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

The most limiting accident for the SDM requirements is based on a 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. As RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value is reached. 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

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APPLICABLE SAFETY ANALYSES (continued)

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.

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

a. An uncontrolled rod withdrawal from subcritical or low power condition;

b. Startup of an inactive reactor coolant pump (RCP); and

c. Rod ejection.

Each of these events is discussed below.

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

The startup of an inactive loop event is defined as an uncontrolled reduction in SHUTDOWN MARGIN resulting from the startup of an RCP on an idle loop containing a reduced coolant temperature or boron concentration. Adherence to LCO 3.4.18, "RCS Isolated Loop Startup," ensures that the preconditions necessary for significant reactivity insertion during the startup of an inactive loop (i.e., reduced coolant temperature or boron concentration on an idle and unisolated loop) cannot be achieved under credible circumstances. Recirculation of reactor coolant in an isolated loop through a loop stop valve bypass line prior to loop unisolation when performed in accordance with LCO 3.4.18 does not constitute an uncontrolled boron dilution event. The accident analysis demonstrates that sufficient time exists for corrective operator action in response to a postulated reactivity insertion resulting from the recirculation activity.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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) accident is the most limiting analysis that establishes 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 Regulatory Guide 1.183 limits (Ref. 3).

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 with k_{eff} > 1.0, 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

(continued)

BASES

ACTIONS

A.1 (continued)

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 unit conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% $\Delta k/k$ must be recovered and a boration flow rate of 10 gpm, it is possible to increase the boron concentration of the RCS by 100 ppm in approximately 59 minutes. If a boron worth of 10 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta k/k$. These boration parameters of 10 gpm and 12,950 ppm represent typical values 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 MODE 2 with $k_{eff} < 1.0$ and MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control and shutdown 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).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 3.1.22.

2. UFSAR, Chapter 15.

3. Regulatory Guide 1.183, July 2000.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and 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.

(continued)

BASES

BACKGROUND (continued)

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.

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 unit 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 unit 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

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 ± 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

(continued)

BASES

LCO (continued)

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. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 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. 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 unit systems.

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 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 any normalization of predicted core reactivity to the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1 (continued)

measured value 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Sections 3.1.22, 3.1.24, and 3.1.25.

2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 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 or equal to 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 unit accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles 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.

(continued)

BASES

BACKGROUND (continued)

If the LCO limits are not met, the unit response during transients may not be as predicted. For example, 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.

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, Chapter 15 (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 the MTC is positive. Such accidents include the rod withdrawal transient from either zero or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

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 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 safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at BOC; this upper bound must not be exceeded. This maximum upper limit occurs at BOC, all rods out (ARO), hot zero power conditions. 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, therefore, the conditions of the LCO can only be ensured through measurement. 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 upper limit and the lower limit are 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.

BASES

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 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 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 be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life 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.

(continued)

BASES

ACTIONS

B.1 (continued)

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 unit systems.

C.1

Exceeding the lower MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the lower MTC limit is exceeded, 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 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 unit 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 upper 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 to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

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 lower LCO limit. The 300 ppm SR value is sufficiently less negative than the lower LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

a. The SR is not required to be performed until 7 Effective Full Power Days (EFPDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.

b. If the 300 ppm Surveillance limit is exceeded, it is possible that the lower limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 EFPDs 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 lower limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

REFERENCES

1. UFSAR, Section 3.1.7.

2. UFSAR, Chapter 15.

3. VEP-FRD-42-A, "Reload Nuclear Design Methodology."

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 GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Capability" (Ref. 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 may be further subdivided into two groups to provide for precise reactivity control. A group consists of four RCCAs that are electrically paralleled to step simultaneously. If a bank of RCCAs consists of two groups,

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BASES

BACKGROUND (continued)

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, 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.

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 System provides a highly accurate indication of actual 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. The RPI system is capable of monitoring rod position within at least ± 12 steps.

BASES

APPLICABLE SAFETY ANALYSES

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

a. There be no violations of:

   1. specified acceptable fuel design limits, or
   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 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 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 and shutdown 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.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 5).

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.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

Continued operation of the reactor with a misaligned rod is allowed if power is reduced or if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy rise 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 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).

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on rod OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The 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.

(continued)

BASES

LCO (continued)

The LCO has been modified by a Note. The Note permits a wider tolerance on indicated rod position for a maximum of one hour in every 24 hours to allow stabilization of known thermal drift in the individual rod position indicator channels. This thermal soak time is available both for a continuous one hour period or several discrete intervals as long as the total time does not exceed 1 hour in any 24 hour period and the indicated rod position does not exceed 24 steps from the group step counter demand position. This allowance applies to the indicated position of the rod, not its actual position. If the actual position is known to be greater than 12 steps from the group step counter demand position, the Conditions and Required Actions of the specification must be followed.

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the unit. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the rods are normally bottomed and the reactor is shut down and not producing fission 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 (SDM)," 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.

BASES

ACTIONS (continued)

A.2

If the inoperable rod(s) cannot be restored to OPERABLE status, 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.

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 unit systems.

B.1.1 and B.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 C 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 in significantly to meet the overlap requirements.

Power operation may continue with one RCCA OPERABLE 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. 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.

B.2.1, B.2.2.1, B.2.2.2, and B.3

For continued operation with a misaligned rod, RTP must be reduced or 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 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 4). The Completion Time

(continued)

BASES

ACTIONS

B.2.1, B.2.2.1, B.2.2.2, and B.3 (continued)

of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

Alternatively, verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits ensures that current operation with a rod misaligned does not result in power distributions that may invalidate safety analysis assumptions. 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 $F^N_{\Delta H}$.

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 15 (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 unit 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

(continued)

BASES

ACTIONS

D.1.1 and D.1.2 (continued)

described in the Bases or 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.

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 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 unit 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. If an individual rod position is not within the alignment limit of the group step counter demand position, a determination must be made whether the problem is the actual rod position or the indicated rod position. If the actual rod position is not within the alignment limit, follow the Conditions and Required Actions in Specification 3.1.4. If the indicated, not actual, rod position is not within the alignment limit, follow the Conditions and Required Actions of Specification 3.1.7, Rod Position Indication. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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, 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 based on operating experience, equipment reliability, and plant risk and 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.

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. For this surveillance, a fully withdrawn position of 230 steps is used in order to provide consistent test conditions to facilitate trending. This rod position is not necessarily the same as the cycle-dependent fully withdrawn rod position specified in the COLR and will yield conservative drop times relative to the COLR position. The surveillance procedure limits for rod drop time ensure that the Surveillance Requirement criterion and the Safety Analysis Limit are met.

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

BASES

REFERENCES

1. UFSAR, Sections 3.1.6 and 3.1.22.

2. 10 CFR 50.46.

3. UFSAR, Chapter 15.

4. UFSAR, Section 15.2.3.

5. UFSAR, Section 4.3.1.5.

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 GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 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 is further subdivided into two groups to provide for precise reactivity control. A group consists of four 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 LCO 3.1.7, "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.

(continued)

BASES

BACKGROUND (continued)

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 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 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 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.

BASES

APPLICABLE SAFETY ANALYSES (continued)	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).
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, or 5, the shutdown banks are 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 bank to move below the LCO limits, which would normally violate the LCO. Should the SR testing be suspended due to equipment malfunction with a rod bank below the insertion limit, the applicable Condition should be entered.
ACTIONS	<u>A.1.1, A.1.2 and A.2</u> When one or more shutdown banks is not within insertion limits, except as allowed by Condition B, 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

(continued)

BASES

ACTIONS

A.1.1, A.1.2 and A.2 (continued)

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 unit to remain in an unacceptable condition for an extended period of time.

B.1 and B.2

If a shutdown bank is inserted below the insertion limits, power operation may continue for up to 72 hours provided that the bank is not inserted more than 18 steps below the insertion limits, the control and shutdown rods are within the operability and rod group alignment requirements provided in LCO 3.1.4, and the control banks are within the insertion limits provided in LCO 3.1.6. The requirement to be in compliance with LCO 3.1.4 and LCO 3.1.6 ensures that the rods are trippable, and power distribution is acceptable during the time allowed to restore the inserted rod. If any of these Conditions are not met, Condition A must be applied.

The Completion Time of 72 hours is based on operating experience and provides an acceptable time for evaluating and repairing problems with the rod control system.

C.1

If the Required Action and associated Completion Time of Conditions A or B are not met, 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 unit 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.

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position, after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Sections 3.1.6, 3.1.22, and 3.1.24.

2. 10 CFR 50.46.

3. UFSAR, Chapter 15.

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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 GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 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 is further subdivided into two groups to provide for precise reactivity control. A group consists of four 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 LCO 3.1.7, "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 sequenced and moved in an overlap pattern. Overlap is the distance travelled together by two control banks. Sequencing is the order in which the banks are moved. For example, if the fully withdrawn position is 231 steps, as in

(continued)

BASES

BACKGROUND (continued)

Figure B 3.1.6-1, control bank D will begin to move with bank C on a withdrawal when control bank C is at 128 steps. The fully withdrawn position, as well as proper overlap and sequence, are defined in the COLR.

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 limit fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant to within acceptable limits 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 maintain power distributions that limit fuel cladding failures to within acceptable limits in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria for addressing 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).

The SDM requirement is ensured by limiting the control bank insertion limits so that 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. 3).

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 bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

The insertion limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

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

(continued)

BASES

LCO (continued)

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 MODE 2 with $k_{eff} < 1.0$, and 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. Should the SR testing be suspended due to equipment malfunction with a rod bank below the insertion limits, the applicable Condition should be entered.

ACTIONS

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

If the control banks are found to be out of sequence or in the wrong overlap configuration, except as allowed by Condition C, 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.

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 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.

(continued)

BASES

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2 (continued)

When the control banks are outside the acceptable insertion limits, except as allowed by Condition C, 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.

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 unit to remain in an unacceptable condition for an extended period of time.

C.1 and C.2

If Control Banks A, B, or C are inserted below the insertion limits or sequencing or overlap limits are not met, power operation may continue for up to 72 hours provided that the bank is not inserted more than 18 steps below the insertion limits, the control and shutdown rods are within the operability and rod group alignment requirements provided in LCO 3.1.4, and the shutdown banks are within the insertion limits provided in LCO 3.1.5. The requirement to be in compliance with LCO 3.1.4 and LCO 3.1.5 ensures that the rods are trippable, and power distribution is acceptable during the time allowed to restore the inserted rod. If any of these Conditions are not met, Condition B must be applied.

The Completion Time of 72 hours is based on operating experience and provides an acceptable time for evaluating and repairing problems with the rod control system.

D.1

If Required Actions A.1 and A.2, B.1 and B.2, or C.1 and C.2 cannot be completed within the associated Completion Times, the unit 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 unit 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 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. Verifying the predicted critical rod bank position within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the verification with other startup activities.

SR 3.1.6.2

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Sections 3.1.6, 3.1.22, and 3.1.24.

2. 10 CFR 50.46.

3. UFSAR, Chapter 15.

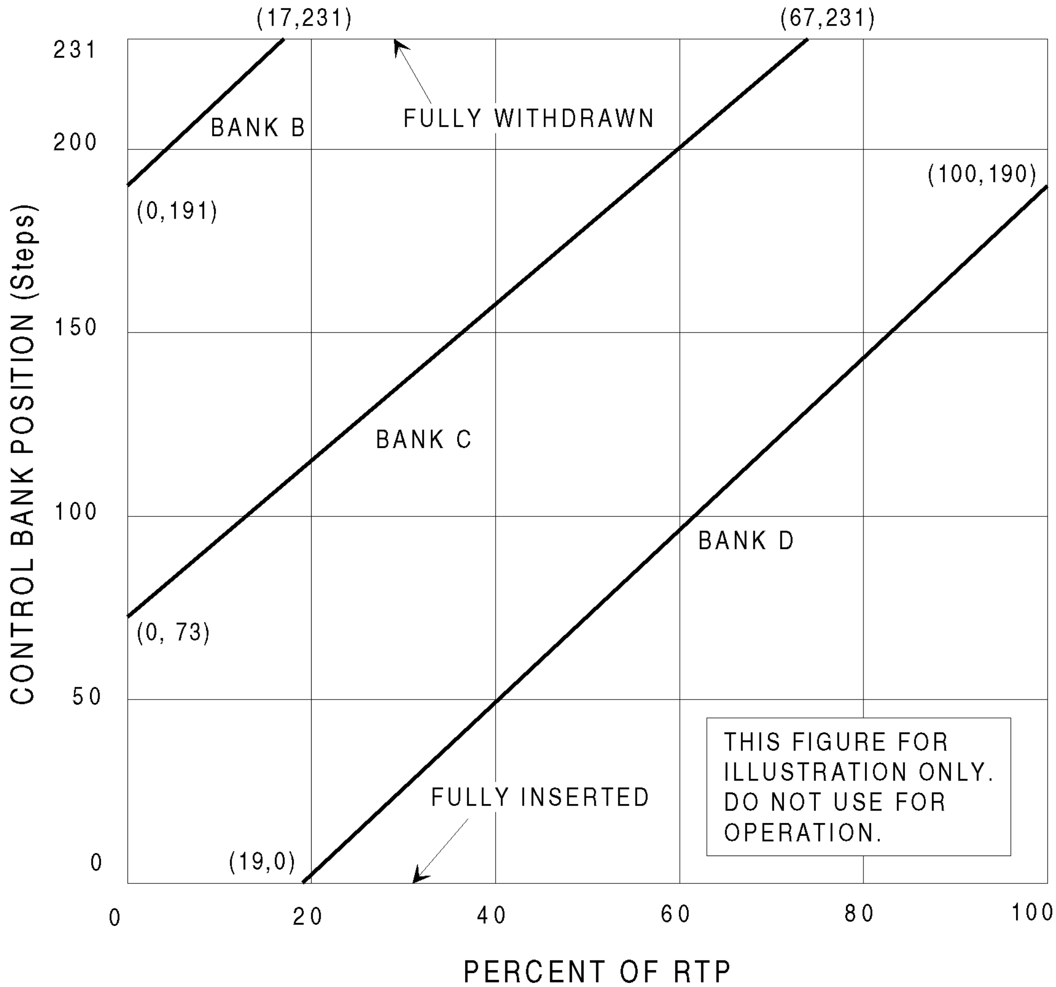

Figure B 3.1.6-1 (page 1 of 1)
Control Bank Insertion vs. Percent RTP

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B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 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 is required to ensure OPERABILITY of the rod position indicators to determine rod positions and thereby ensure compliance with the rod alignment and insertion limits.

The OPERABILITY, including position indication, 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 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 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.

(continued)

BASES

BACKGROUND (continued)

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.

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 a highly accurate indication of actual 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. The RPI System is capable of monitoring rod position within at least ± 12 steps.

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 unit 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).

BASES

LCO

LCO 3.1.7 specifies that the RPI System and the Bank Demand Position Indication System be OPERABLE for each rod. For the rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The RPI System indicates within 12 or 24 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits"; In addition, rod position indication for a single rod can be determined by measuring control rod drive mechanism (CRDM) stationary gripper coil voltage using a temporary monitoring device that provides alarm capability; and

b. 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 rod bank position.

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

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 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 unit. 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 RPI 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 ensuring 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 or C.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 (Ref. 2).

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 unit systems and allowing for rod position determination by Required Action A.1 above.

A Note has been added to Conditions A.3.1 and A.3.2 to ensure that the alternate monitoring requirements are not used as a long term means of verifying rod position. The intended use of this alternate is to allow for monitoring until plant entry into a Mode 5 outage of sufficient duration and repair of the RPI can be safety performed. This ensures that at most, the alternate is used for 18 months or one operating cycle.

BASES

ACTIONS

A.3.1

When one RPI fails, the position of the rod can still be determined by use of the movable incore detectors. 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 or C.2 below is required. Therefore, verification of control rod 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. To provide verification of reliability of alternate monitoring, rod position will be verified by movable incore detectors every 31 days. The 31-day frequency minimizes use of the movable incore monitoring system and can be performed concurrently with existing surveillance requirements for Hot Channel Factors.

A.3.2

Review of control rod CRDM stationary gripper coil voltage using the alternate monitoring method for indication of control rod movement for the rod with inoperable position indicator will be within 16 hours and then every 8 hours thereafter. Verification of control rod 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. Should CRDM stationary gripper coil voltage of the control rod indicate movement, a determination of the control rod position will be made using the movable incore detectors within 8 hours. To provide verification of reliability of alternate monitoring, rod position will be verified by movable incore detectors every 31 days. The 31-day frequency minimizes use of the movable incore monitoring system and can be performed concurrently with existing surveillance requirements for Hot Channel Factors.

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

(continued)

ACTIONS

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

manual assures unplanned rod motion will not occur. 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.

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 ensuring 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 RPI system to operation while avoiding the plant challenges associated with a 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 or C.2 below is required.

C.1 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 and A.2, or B.1, as applicable, are still appropriate but must be initiated promptly under Required Action C.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours 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 4 hours provides an acceptable period of time to verify the rod positions.

D.1.1 and D.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 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 (Ref. 2). The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions D.1.1 and D.1.2 or reduce power to ≤ 50% RTP.

E.1

If the Required Actions cannot be completed within the associated 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 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Performing a CHANNEL CALIBRATION on each RPI channel ensures that the RPI electronics are operating properly. This CHANNEL CALIBRATION involves injecting a test signal into the RPI electronics and verifying or adjusting the

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.1.7.1 (continued) calibration from that point forward. The CHANNEL CALIBRATION also verifies all alarms and indications, such as the Rod Bottom lights. The CHANNEL CALIBRATION does not include the coil stack, as it cannot be adjusted. The indicated RPI position is adjusted as needed to compensate for thermal drift. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 3.1.9. 2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Primary Grade Water Flow Path Isolation Valves

BASES

BACKGROUND

During MODES 3, 4, and 5 operations, the isolation valves for primary grade water flow paths that are connected to the Reactor Coolant System (RCS) must be closed to prevent unplanned boron dilution of the reactor coolant. The isolation valves must be locked, sealed, or otherwise secured in the closed position.

The Chemical and Volume Control System is capable of supplying borated and unborated water to the RCS through various flow paths. Since a positive reactivity addition made by an uncontrolled reduction of the boron concentration is inappropriate during MODES 3, 4 and 5, isolation of all primary grade water flow paths prevents an unplanned boron dilution.

APPLICABLE SAFETY ANALYSES

The possibility of an inadvertent boron dilution event (Ref. 1) occurring during MODES 3, 4, or 5 is precluded by adherence to this LCO, which requires that the primary grade water flow path be isolated. Closing the required valves prevents the flow of significant volumes of primary grade water to the RCS. The valves are used to isolate primary grade water flow paths. These valves have the potential to indirectly allow dilution of the RCS boron concentration. By isolating primary grade water flow paths, a safety analysis for an uncontrolled boron dilution accident is not required for MODES 3, 4 or 5.

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

LCO

This LCO requires that primary grade water be isolated from the RCS to prevent unplanned boron dilution during MODES 3, 4, and 5.

For Unit 1, primary grade water flow paths may be isolated from the RCS by closing valve 1-CH-217. Alternatively, 1-CH-220, 1-CH-241, 1-CH-FCV-1114B and 1-CH-FCV-1113B may be used in lieu of 1-CH-217. For Unit 2, primary grade water

(continued)

BASES

LCO (continued)

flow paths may be isolated from the RCS by closing valve 2-CH-140. Alternatively, 2-CH-160, 2-CH-156, 2-CH-FCV-2114B, and 2-CH-FCV-2113B may be used in lieu of 2-CH-140.

The LCO is modified by a Note which allows the primary grade water flow path isolation valves to be opened under administrative control for planned boron dilution or makeup activities.

APPLICABILITY

This LCO is applicable in MODES 3, 4, and 5 to prevent an inadvertent boron dilution event by ensuring closure of all primary grade water flow path isolation valves.

In MODE 6, LCO 3.9.2, "Primary Grade Water Flow Path Isolation Valves—MODE 6," requires all primary grade water isolation valves to be closed to prevent an inadvertent boron dilution.

In MODES 1 and 2, the boron dilution accident was analyzed and was found to be capable of being mitigated.

ACTIONS

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

Preventing inadvertent dilution of the reactor coolant boron concentration is dependent on maintaining the primary grade water flow path isolation valves locked, sealed, or otherwise secured closed, except as allowed under administrative control by the LCO Note. Because of the possibility of an inadvertent boron dilution, Required Action A.1 prohibits other positive reactivity additions while securing the isolation valves on the primary grade water system. The Completion Time of "Immediately" for suspending positive reactivity additions reflects the importance of preventing known positive reactivity additions so that any boron dilution event can be readily identified and terminated.

The Required Action A.2 Completion Time of 15 minutes for securing the isolation valves provides sufficient time to close and secure the isolation valves on the primary grade water flow paths while minimizing the probability of an unintentional dilution during the Completion Time. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened.

(continued)

BASES

ACTIONS

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

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

The performance of Surveillance 3.1.1.1 under Required Action A.3 verifies that the SDM is within the limits provided in the COLR. It is performed to verify that the required SDM still exists and any inadvertent boron dilution that may have occurred has been detected and corrected. The Completion Time of 4 hours is reasonable, based on the time required to request and analyze an RCS water sample to determine the boron concentration and to compute the SDM.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The primary grade water flow path isolation valves are to be locked, sealed, or otherwise secured closed to isolate possible dilution paths. The likelihood of a significant reduction in the boron concentration during MODES 3, 4, and 5 is remote due to the large mass of borated water in the RCS and the fact that the specified primary grade water flow paths are isolated, precluding a dilution. The SHUTDOWN MARGIN is verified every 24 hours during MODES 3, 4, and 5 under SR 3.1.1.1. The Frequency is based on the time required to verify that the isolation valves in the utilized flow path are locked, sealed, or otherwise secured in the closed position following a boron dilution or makeup activity.

REFERENCES

1. UFSAR, Section 15.2.4.

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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 unit. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, at high power, and after each refueling. 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. 4).

(continued)

BASES

BACKGROUND (continued)

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 PHYSICS TESTS required for reload fuel cycles (Ref. 5) are listed below:

a. Critical Boron Concentration—All Banks Withdrawn;

b. Differential Boron Worth;

c. Bank Worth;

d. Isothermal Temperature Coefficient (ITC); and

e. Neutron Flux Symmetry.

The first four tests are performed in MODE 2, and the last test is performed in MODE 1. These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

a. The Critical Boron Concentration—Control Rods Withdrawn Test measures the critical boron concentration at hot zero power (HZP). With all rods out, the lead control bank is at or near its fully withdrawn position. HZP is where the core is critical (k_{eff} = 1.0), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test should not violate any of the referenced LCOs.

b. The Differential Boron Worth Test determines if the measured differential boron worth is consistent with the predicted value. With the core at HZP, the change in equilibrium boron concentration is determined at different rod bank positions. As the rod bank or banks are moved, the reactivity change is measured using a reactivity computer. The measured reactivity change is divided by the difference in measured critical boron

(continued)

BASES

BACKGROUND

b. (continued)

concentrations to determine the differential boron worth. The insertion of the rod bank could result in violation of LCO 3.1.4, "Rod Group Alignment Limits," LOC 3.1.5, "Shutdown Bank Insertion Limits," or LCO 3.1.6, "Control Bank Insertion Limits."

c. The Bank Worth Test is used to measure the reactivity worth of selected banks. This test is performed at HZP and has three alternative methods of performance. The first method, the Boron Exchange Method, varies the reactor coolant boron concentration and moves the selected bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining banks. The second method, the Rod Swap Method, measures the worth of a predetermined reference bank using the Boron Exchange Method above. The reference bank is then nearly fully inserted into the core. The selected bank is then inserted into the core as the reference bank is withdrawn. The HZP critical conditions are then determined with the selected bank fully inserted (0-2 steps withdrawn) into the core. The worth of the selected bank is inferred, based on the position of the reference bank with respect to the selected bank. This sequence is repeated as necessary for the remaining banks. The third method, the Boron Endpoint Method, moves the selected bank over its entire length of travel and then varies the reactor coolant boron concentration to achieve HZP criticality again. The difference in boron concentration is the worth of the selected bank. This sequence is repeated for the remaining banks. Performance of this test could violate LCO 3.1.4, LCO 3.1.5, or LCO 3.1.6.

d. The ITC Test measures the ITC of the reactor. This test is performed at HZP and has two methods of performance. The first method, the Slope Method, varies RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of two or more calculated ITCs. The second method, the Endpoint Method,

(continued)

BASES

BACKGROUND

d. (continued)

changes the RCS temperature and measures the reactivity at the beginning and end of the temperature change. The ITC is the total reactivity change divided by the total temperature change. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two or more calculated ITCs. Performance of this test could violate LCO 3.4.2, "RCS Minimum Temperature for Criticality."

e. Flux symmetry verification is necessary prior to exceeding 30% rated thermal power to determine if any core anomalies exist (i.e., dropped rods, fuel misloading, etc.) as described in ANSI/ANS-19.6.1-2011 (Ref. 4). Flux symmetry verification may be performed by direct power distribution measurement (M/D flux map) or by indirect measurement (e. g. control rod worth). A direct power distribution measurement (M/D flux map) is necessary prior to exceeding 30% rated thermal power unless a confirmatory indirect measurement of flux symmetry has been attained which defers the requirement for a direct power distribution measurement (M/D flux map) prior to exceeding 50% rated thermal power.

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 Reference 6. 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.

The UFSAR defines requirements for initial testing of the facility, including PHYSICS TESTS. Tables 14.1-1, 14.1-2, and 14.1-3 summarize the zero, low power, and power tests. Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-2011 (Ref. 4). 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, LCO 3.1.5, LCO 3.1.6, and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LCO 3.4.2 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 banks), 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.

Reference 7 allows special test exceptions (STEs) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

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 banks 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" to provide input to the reactivity computer. 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.

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 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.

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The Applicability stated as "during PHYSICS TESTS initiated in MODE 2" to ensure that the 5% RTP maximum power

(continued)

BASES

APPLICABILITY (continued)

level is not exceeded. Should the THERMAL POWER exceed 5% RTP and, consequently, enter MODE 1, this Applicability statement prevents exiting the Specification and its Required Action.

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 unit 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.

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 unit 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 and associated Completion Times cannot be completed within the associated 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 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 unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.9.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS. Performance of the normally scheduled COT is sufficient to ensure the equipment is OPERABLE. LCO 3.3.1 requires a COT on the power range and intermediate range channels every 92 days. These Frequencies have been determined to be sufficient for verification that the equipment is working properly. Because initiation of PHYSICS TESTS does not affect the ability of the equipment to perform its function or the RTS trip capability, and does not invalidate the previous Surveillances, requiring the testing to be performed at a fixed time prior to the initiation of PHYSICS TESTS has no benefit.

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. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 unit is not operating in a condition that could invalidate the safety analyses. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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. Rod bank position;

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.9.4 (continued)

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration;

g. Isothermal temperature coefficient (ITC), when below the point of adding heat (POAH);

h. Moderator Defect when above the POAH; and

i. Doppler Defect when above the POAH.

Using the ITC accounts for Doppler reactivity in this calculation when the reactor is subcritical or critical but below the POAH, and the fuel temperature will be changing at the same rate as the RCS.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

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

2. 10 CFR 50.59.

3. Regulatory Guide 1.68, Revision 2, August, 1978.

4. ANSI/ANS-19.6.1-2011, January 13, 2011.

5. VEP-FRD-36, Rev. 0.3-A, "Control Rod Reactivity Worth Determination by the Rod Swap Technique."

6. VEP-FRD-42-A, "Reload Nuclear Design Methodology."

7. WCAP-11618, including Addendum 1, April 1989.

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 steady state conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$, $F_Q^M(Z)$. However, because this value represents a steady state condition, it does not encompass the variations in the value of $F_Q(Z)$ that are present during nonequilibrium situations, such as load changes.

To account for these possible variations, the steady state limit for $F_Q(Z)$ is adjusted by an elevation dependent factor that accounts for the calculated worst case transient conditions.

Core monitoring and control under nonsteady state 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 loss of coolant accident (LOCA), the peak cladding temperature during a small break LOCA must not exceed 2200°F, and there must be a high level of probability that the peak cladding temperature does not exceed 2200°F for the large breaks (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 unirradiated fuel is limited to 225 cal/gm and irradiated fuel is limited to 200 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.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

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

BASES

LCO

The Measured Heat Flux Hot Channel Factor, $F_Q^M(Z)$, shall be limited by the following relationships, as described in Reference 4:

$$F_Q^M(Z) \leq \frac{CFQ}{P} \frac{K(Z)}{N(Z)} \quad \text{for } P > 0.5$$

$$F_Q^M(Z) \leq \frac{CFQ}{0.5} \frac{K(Z)}{N(Z)} \quad \text{for } P \leq 0.5$$

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,

N(Z) is a cycle dependent function that accounts for power distribution transients encountered during normal operation. N(Z) is included in the COLR; and

P is the fraction of RATED THERMAL POWER defined as

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

The actual values of CFQ, K(Z), and N(Z) are given in the COLR; however, CFQ is normally approximately 2, K(Z) is a function that looks like the one provided in Figure B 3.2.1-1, and N(Z) is a value greater than 1.0.

An $F_Q^M(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value of $F_Q(Z)$. Then, the measured $F_Q^M(Z)$ is increased by 1.03 which is a factor that accounts for fuel manufacturing tolerances and 1.05 which accounts for flux map measurement uncertainty (Ref. 4).

The FQ(Z) limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during a small break LOCA and assures with a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks (Ref. 1).

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

(continued)

BASES

LCO (continued)

such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

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

If $F_Q^M(Z)$ exceeds its specified limits, reducing the AFD limit by ≥ 1% for each 1% by which $F_Q^M(Z)$ exceeds its limit within the allowed Completion Time of 15 minutes, restricts the axial flux distribution such that even if a transient occurred, core peaking factors are not exceeded. The maximum AFD limits initially determined by Required Action A.1 may be affected by subsequent determinations of $F_Q^M(Z)$ and would require AFD reductions with 15 minutes of the $F_Q^M(Z)$ determination, if necessary.

A.2.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^M(Z)$ exceeds its limit, maintains an acceptable absolute power density. The percent that $F_Q^M(Z)$ exceeds the limit can be determined from:

$$\left\{\text{maximum over z}\left(\frac{F_Q^M(Z)}{\frac{CFQ\ K(Z)}{P\ \ N(Z)}}\right)-1.0\right\}\times 100 \quad \text{for } P > 0.5$$

$$\left\{\text{maximum over z}\left(\frac{F_Q^M(Z)}{\frac{CFQ\ K(Z)}{0.5\ N(Z)}}\right)-1.0\right\}\times 100 \quad \text{for } P \le 0.5$$

(continued)

BASES

ACTIONS

A.2.1 (continued)

$F_Q^M(Z)$ is the measured $F_Q(Z)$ multiplied by factors 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 unit to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.2.1 may be affected by subsequent determinations of $F_Q^M(Z)$ and would require power reductions within 15 minutes of the $F_Q^M(Z)$ determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F_Q^M(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2.2

A reduction of the Power Range Neutron Flux–High trip setpoints by ≥ 1% for each 1% by which $F_Q^M(Z)$ 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.2.1. The maximum allowable Power Range Neutron Flux–High trip setpoints initially determined by Required Action A.2.2 may be affected by subsequent determinations of $F_Q^M(Z)$ and would require Power Range Neutron Flux–High trip setpoint reductions within 72 hours of the $F_Q^M(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux–High trip setpoints. Decreases in $F_Q^M(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux–High trip setpoints.

A.2.3

Reduction in the Overpower ΔT trip setpoints (value of K_4) by ≥ 1% (in ΔT span) for each 1% by which $F_Q^M(Z)$ 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.2.1. The

(continued)

BASES

ACTIONS

A.2.3 (continued)

maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.2.3 may be affected by subsequent determinations of $F_Q^M(Z)$ and would require Overpower ΔT trip setpoint reductions within 72 hours of the $F_Q^M(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F_Q^M(Z)$ would allow increasing the maximum Overpower ΔT trip setpoints.

A.2.4

Verification that $F_Q^M(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 prior to increasing THERMAL POWER above the limit imposed by Required Action A.2.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

B.1

If Required Actions A.1, A.2.1, A.2.2, A.2.3, or A.2.4 are not met within their associated Completion Times, the unit must be placed in a MODE or condition in which the LCO requirements are not applicable. This is done by placing the unit 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 is modified by a Note. It states that THERMAL POWER may be increased until a power level for extended operation 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 $F_Q^M(Z)$ is within its specified limit after a power rise of more than 10% RTP over the THERMAL POWER at which it was last verified to be within specified limits. In the absence of this Frequency condition, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^M(Z)$. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

verification after a power level is achieved for extended operation that is 10% higher than that power at which F_Q was last measured.

SR 3.2.1.1

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 N(Z).

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

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q^M(Z)$ 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 $F_Q^M(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q^M(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

Flux map data are taken for multiple core elevations. $F_Q^M(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 8% inclusive; and

b. Upper core region, from 92 to 100% inclusive.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 (continued)

The top and bottom 8% (Reference 5) 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 that more frequent surveillances be performed. An evaluation of the expression below is required to account for any increase to $F_Q^M(Z)$ that may occur and cause the $F_Q^M(Z)$ limit to be exceeded before the next required $F_Q^M(Z)$ evaluation.

If the two most recent $F_Q^M(Z)$ evaluations show an increase in the expression

$$\text{maximum over z} \qquad \left[\frac{F_Q^M(Z)}{K(Z)}\right],$$

it is required to meet the $F_Q^M(Z)$ limit with the last $F_Q^M(Z)$ increased by the appropriate factor, or to evaluate $F_Q^M(Z)$ more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit without detection.

REFERENCES

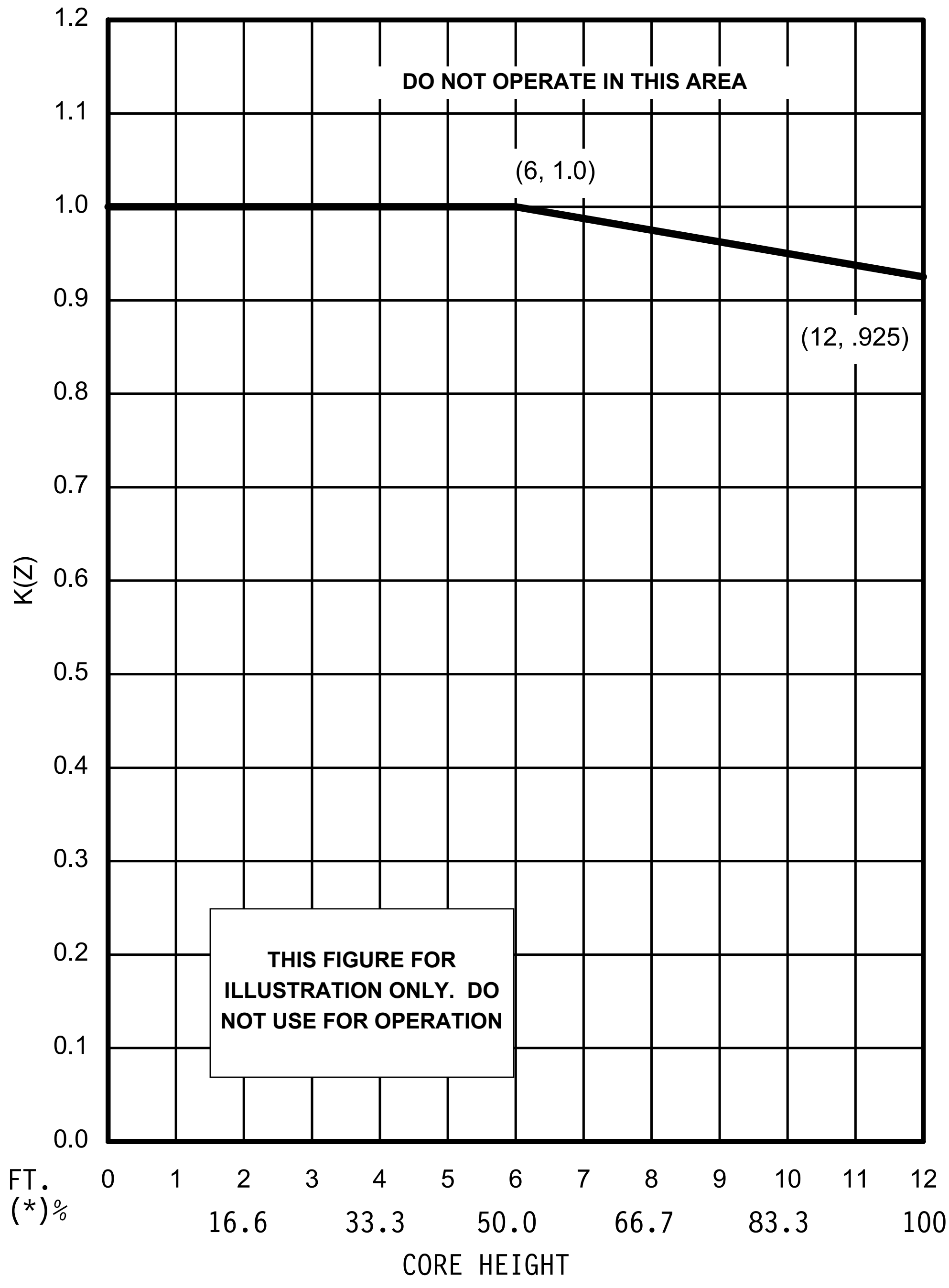
1. 10 CFR 50.46.

2. VEP-NFE-2-A, "VEPCO Evaluation of the Control Rod Ejection Transient."

3. UFSAR, Section 3.1.22.

4. VEP-NE-1-A, "VEPCO Relaxed Power Distribution Control Methodology and Associated FQ Surveillance Technical Specifications."

5. ETE-NAF-2016-033, "Implementation of Revised Bases of Axial Exclusion Zones for TS Bases 3.2.1 Surveillance Requirements."



* FOR CORE HEIGHT OF 12 FEET

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

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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 precludes DNB and is met by limiting the minimum local DNB heat flux ratio to a value greater than the design limits. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

(continued)

BASES

BACKGROUND (continued)	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 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 loss of coolant accident (LOCA), the peak cladding temperature during a small break LOCA must not exceed 2200°F, and there must be a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks;

c. During an ejected rod accident, the energy deposition to unirradiated fuel is limited to 225 cal/gm and irradiated fuel is limited to 200 cal/gm (Ref. 1); 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. 2).

For transients that may be DNB limited, the Reactor Coolant System flow, temperature, and pressure, and $F^N_{\Delta H}$ are the 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 is met by limiting the minimum DNBR to a value which provides 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, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

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 ($F^N_{\Delta H}$)," LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)," and LCO 3.4.1, "RCS Pressure, Temperature, and Flow DNB Limits."

$F^N_{\Delta H}$ 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 the design radial peaking 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.

BASES

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. The design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have sufficient margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

ACTIONS

A.1 and A.2

Condition A is modified by a Note that requires that Required Actions A.3 and A.4 must be completed whenever Condition A is entered. Thus, because even if $F^N_{\Delta H}$ is restored to within limits, Required Action A.3 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.4 requires that another determination of $F^N_{\Delta H}$ must be done 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.3 is performed if power ascension is delayed past 24 hours.

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 and reduce the Power Range Neutron Flux—High to ≤ 55% RTP in accordance with Required Action A.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 provides an acceptable time to reach the required power level from full power operation without allowing the unit to remain in an unacceptable condition for an extended period of time.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.2 recognizes that, once power is reduced, the safety analysis assumptions are

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

satisfied 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.3

Once the power level has been reduced to < 50% RTP per Required Action A.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 Action A.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.4

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 through A.4 cannot be completed within their required Completion Times, the unit must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the unit 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 unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

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 $F^N_{\Delta H}$ limit contains an allowance of 1.04 to account for measurement uncertainty.

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. VEP-NFE-2-A, "VEPCO Evaluation of the Control Rod Ejection Transient."

2. UFSAR, Section 3.1.22.

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 Power Distribution Control (RPDC) 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.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RPDC methodology (Ref. 1) establishes a xenon distribution library with tentatively wide AFD limits. 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 important Condition 4 event is the LOCA. The most important Condition 3 event is the loss of flow accident. The most important Condition 2 events are uncontrolled rod withdrawal, excessive heat removal, and boration or 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. 2). 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.

(continued)

BASES

LCO (continued)

The AFD limits are provided in the COLR. Figure B 3.2.3-1 shows typical RPDC AFD limits. The AFD limits for RPDC 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 RPDC 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 unit 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. VEP-NE-1-A, "VEPCO Relaxed Power Distribution Control Methodology and Associated FQ Surveillance Technical Specifications."
2. UFSAR, Chapter 7.

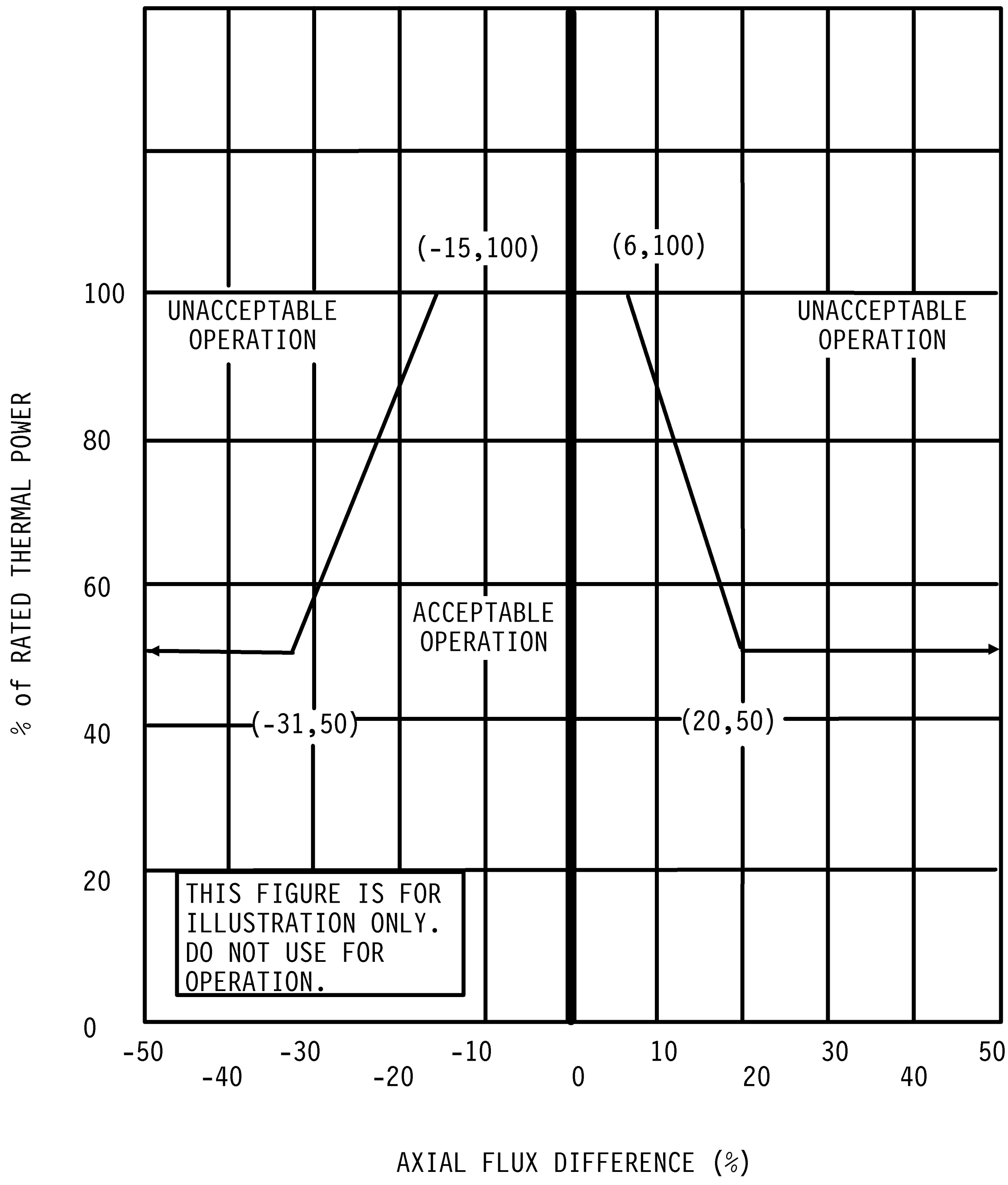

Figure B 3.2.3-1 (page 1 of 1)
AXIAL FLUX DIFFERENCE Acceptable Operation Limits
as a Function of RATED THERMAL POWER

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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 by using the movable incore detector system to obtain full core flux maps. Between these full core flux maps, the excore neutron detectors are used to monitor QPTR, which is a measure of changes in the radial power distribution. QPTR is defined in Section 1.1 in terms of ratios of excore detector calibrated output. However, the movable incore detector system can measure changes in the relative power of symmetrically located incore locations or changes in the incore tilt, which can be used to calculate an equivalent QPTR.

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 loss of coolant accident (LOCA), the peak cladding temperature during a small break LOCA must not exceed 2200°F, and there must be a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks (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;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. During an ejected rod accident, the energy deposition to unirradiated fuel is limited to 225 cal/gm and irradiated fuel is limited to 200 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.

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.

BASES

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 the revised limit.

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 $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F^N_{\Delta H}$ 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 a 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 unit and perform a flux map. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition.

(continued)

BASES

ACTIONS

A.3 (continued)

If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F^N_{\Delta H}$ 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 $F^N_{\Delta H}$ 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 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

(continued)

BASES

ACTIONS

A.5 (continued)

if Required Action A.5 is performed, the 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 $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours of reaching 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 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.

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

(continued)

BASES

ACTIONS

B.1 (continued)

4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging unit 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

For those causes of QPT 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 verifies that the QPTR, as determined using the movable incore detectors, is within its limits. This Surveillance may be performed in lieu of SR 3.2.4.1, as provided by a SR 3.2.4.1 Note. SR 3.2.4.2 is modified by a Note, which states that it is not required until 12 hours after the inputs from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is > 75% RTP. Therefore, this Surveillance is only required to be performed when one or more Power Range Neutron Flux channels are inoperable, but may be performed to satisfy the routine monitoring of QPTR.

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. Performing SR 3.2.4.2 provides an accurate alternative means for ensuring that any tilt remains within its limits.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

QPTR is determined using the movable incore detectors performing a full core incore flux map or by monitoring 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, taken from the most recent full core flux map used to normalize the excore detectors, to calculate QPTR. If a full core flux map is used to determine QPTR, the measured incore tilt values from the full core flux map are compared to those from the most recent full core flux map used to normalize the excore detectors. The difference between these tilt values is the QPTR for the current core conditions. Therefore, the movable incore detectors can be used to confirm that QPTR is within limits.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.46.
2. VEP-NFE-2-A, "VEPCO Evaluation of the Control Rod Ejection Transient."
3. UFSAR, Section 3.1.22.

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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 Analytic Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytic Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective devices must be chosen to be more conservative than the Analytic Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

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

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BASES

BACKGROUND (continued)

the Trip Setpoint meets the definition of an LSSS (Ref. 9) and could be used to meet the requirement that they be contained in the technical specifications.

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

Use of the Trip Setpoint to define "as found" OPERABILITY and its designation as the LSSS under the expected circumstances described above would result in actions required by both the rule and technical specifications that are clearly not warranted. However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the technical specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value which, as stated above, is the same as the LSSS.

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BASES

BACKGROUND (continued)

The Allowable Value specified in Table 3.3.1-1 serves as the LSSS such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the Trip Setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a Safety Limit is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to have exceeded the Allowable Value the device would be considered inoperable for a technical specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required. Note that, although the channel is "OPERABLE" under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty assumptions stated in the referenced set point methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned.

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 to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2750 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 criteria during AOOs.

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 an acceptable fraction of 10 CFR 50.67 limits. Different accident categories are allowed a different fraction of these limits, based on probability of

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BACKGROUND (continued)

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. 1), 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, bistable 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 bistable 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 trip, or de-energize, and fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often 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 trip setpoints 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 during performance of 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. These setpoints are defined in UFSAR, Chapter 7 (Ref. 1), Chapter 6 (Ref. 2), and Chapter 15 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable 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.

When 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.

When 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). The actual number of channels required for each unit parameter is specified in Reference 1.

Two logic channels are required to ensure no single random failure of a logic channel will disable the RTS. The logic channels are designed such that testing required while the

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BASES

BACKGROUND

Signal Process Control and Protection System (continued)

reactor is at power may be accomplished without causing trip. Provisions to allow removing logic channels from service during maintenance are unnecessary because of the logic system's designed reliability.

Allowable Values and RTS Setpoints

The trip setpoints used in the bistables are based on the analytical limits cited in Reference 3. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation 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 Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservative with respect to the analytical limits. The methodology used to calculate the trip setpoints and Allowable Values, including their explicit uncertainties, is cited in the "RTS/ESFAS Setpoint Methodology Study" (Ref. 6) which incorporates all of the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the determination of each trip setpoint and corresponding Allowable Value. The trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value (LSSS) to account for measurement errors detectable by the COT. The Allowable Value serves as the Technical Specification OPERABILITY limit for the purpose of the COT. 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 bistable is considered OPERABLE.

The trip setpoint is the value at which the bistable is set and is the expected value to be achieved during calibration. The trip setpoint value ensures the LSSS and the safety analysis limits are met for surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as left" setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration + comparator setting uncertainties). The trip

(continued)

BASES

BACKGROUND

<u>Allowable Values and RTS Setpoints</u> (continued)

setpoint value is therefore considered a "nominal" value (i.e., expressed as a value without inequalities) for the purposes of COT and CHANNEL CALIBRATION.

Trip setpoints consistent with the requirements of the Allowable Value ensure that SLs are not violated during AOOs (and 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 AOO or DBA and the equipment functions as designed).

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements of Table 3.3.1-1. 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.

<u>Solid State Protection System</u>

The SSPS equipment is used for the decision logic processing of outputs from 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 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.

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BASES

BACKGROUND

<u>Solid State Protection System</u> (continued)

The 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.

<u>Reactor Trip Switchgear</u>

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening 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 attachment 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 logic Functions are described in the functional diagrams included in Reference 2. In addition to the reactor trip or ESF, these diagrams also describe the various "permissive interlocks" that are associated with unit conditions. Each train has a built in testing device that can automatically test the logic Functions and the actuation devices 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.

BASES

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 specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RTS trip Functions that were credited in the accident analysis.

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 with a trip setpoint value outside its calibration tolerance band 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 the unit conditions. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

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 are 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, even with random failure of one of the other three protection and 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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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. Specific exceptions to the above general philosophy exist and 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. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its trip setpoint.

   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 to be able to trip the reactor. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and 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. 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.

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 positive reactivity excursion leading to DNB during power operations. 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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Power Range Neutron Flux (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 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, 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 approximately 10% RTP (P-10 setpoint). 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, 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, 4, 5, or 6.

3. Power Range Neutron Flux Rate

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

a. Power Range Neutron Flux—High Positive Rate

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. This Function compliments the Power Range Neutron

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Power Range Neutron Flux Rate (continued)

a. Power Range Neutron Flux—High Positive Rate (continued)

Flux—High and Low Setpoint trip Functions to ensure that the 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 may be fully withdrawn in MODE 3, 4, or 5, the remaining complement of control bank (partial withdrawal allowed) worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. 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.

b. Power Range Neutron Flux—High Negative Rate

The Power Range Neutron Flux—High Negative Rate trip Function ensures that protection is provided for multiple rod drop accidents. At high power levels, a multiple rod drop accident could cause local flux peaking that would result in an unconservative local DNBR. DNBR is defined as the ratio of the heat flux required to cause a DNB at a particular location in the core to the local heat flux. The DNBR is indicative of the margin to DNB. No credit is taken for the operation of this Function for those rod drop accidents in which the local DNBRs will be greater than the limit.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Power Range Neutron Flux Rate (continued)

b. Power Range Neutron Flux—High Negative Rate (continued)

The LCO requires all four Power Range Neutron Flux—High Negative Rate channels to be OPERABLE.

In MODE 1 or 2, when there is potential for a multiple rod drop accident to occur, the Power Range Neutron Flux—High Negative Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux—High Negative Rate trip Function does not have to be OPERABLE because the core is not critical and DNB is not a concern. Also, since only the shutdown banks may be fully withdrawn in MODE 3, 4, or 5, the remaining complement of control bank (partial withdrawal allowed) worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn and the required SDM is increased during refueling operations. 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 NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. 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.

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.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Intermediate Range Neutron Flux (continued)

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 core protection for reactivity accidents. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because Source Range Instrumentation channels provide the required reactor trip protection. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required 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 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, 4, and 5 when rods are capable of withdrawal or one or more rods are not fully inserted. Therefore, the functional capability at the trip setpoint is assumed to be available.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Source Range Neutron Flux (continued)

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events.

In MODE 2 when 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 Setpoint trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized and inoperable.

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 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 3.9.3, "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 pressurizer 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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

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 trip setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;
- pressurizer pressure—the trip setpoint is varied to correct for changes in system pressure; and
- axial power distribution-f(ΔI), the 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 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 of 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 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. 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. Additionally, the turbine runback setpoint blocks automatic and manual rod withdrawal. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all three channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

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 DNB. 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.

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 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 function generated by the rate lag controller for T_{avg} dynamic compensation is represented by the expression: $\tau_3 s/1+\tau_3 s$. The time constant utilized in the rate lag controller for T_{avg} is τ_3.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. A turbine runback will reduce turbine power and reactor power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Overpower ΔT (continued)

Additionally, the turbine runback setpoint blocks automatic and manual rod withdrawal. 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. 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.

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. 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.

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 impulse pressure greater than approximately 10% of full power equivalent (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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Pressurizer Pressure (continued)

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.

The LCO requires three channels of the Pressurizer Pressure—High to be OPERABLE.

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 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, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

9. Pressurizer Water Level—High

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 LCO requires three channels of Pressurizer Water Level—High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Pressurizer Water Level—High (continued)

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 reactor high pressure trip.

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 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, which is approximately 30% RTP, 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.

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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Reactor Coolant Pump (RCP) Breaker Position

Both RCP Breaker Position trip Functions operate from three pairs of auxiliary contacts, with one pair on each RCP breaker with one contact supplying each train. These Functions anticipate the Reactor Coolant Flow–Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above the P-8 setpoint, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow–Low (Single Loop) trip setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this trip Function because the RCS Flow–Low trip alone provides sufficient protection of unit SLs 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 a pump.

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

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip must be OPERABLE. In MODE 1 below the P-8 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.

The RCP Breaker Position (Two Loops) 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 and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

11. Reactor Coolant Pump (RCP) Breaker Position (continued)

trip. 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 unit SLs 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 an RCP.

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

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the RCP Breaker Position (Two Loops) 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. Above the P-8 setpoint, a loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

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 bus is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. 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 RCPs channels to prevent reactor trips due to momentary electrical power transients.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

12. Undervoltage Reactor Coolant Pumps (continued)

The LCO requires three Undervoltage RCPs channels to be OPERABLE. Each channel monitors one RCP bus voltage with two sensors. One sensor monitors from A to B phases, while the other sensor senses from the B to C phases.

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.

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. 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 LCO requires three Underfrequency RCPs channels to be OPERABLE with each channel monitoring one bus.

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.

Regarding RCP Underfrequency Testing, it should be noted that test circuits have not been installed on Unit 1, therefore, such testing can only be performed on Unit 2.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

14. Steam Generator Water Level—Low Low

The SG Water Level—Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the Auxiliary Feedwater (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. IEEE 279 requirements are satisfied by 2/3 logic for protection function actuation, thus allowing for a single failure of a channel and still performing the protection function. Control/protection interaction is addressed by the use of the Median Signal Selector (MSS) which prevents a single failure of a channel providing input to the control system requiring protective action. That is, a single failure of a channel providing input to the control system does not result in the control system initiating a condition requiring protective action. The Median Signal Selector performs this by not selecting the channels indicating the highest or lowest steam generator levels as input to the control system. A power failure of the MSS will be annunciated in the control room as a process racks power supply failure. Operation in MODE 1 or 2 with a failure of the MSS requires entry into Condition E for the channel common to the control and protection system for the Steam Generator Water Level-Low Low Function until the affected SG Level Control System is taken out of automatic control or the MSS has been restored to operation. 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. These channels for the SGs measure level with a narrow range span.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

14. Steam Generator Water Level—Low Low (continued)

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level—Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. 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. Decay heat removal is normally accomplished by Main Feedwater System or AFW System in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

15. Deleted

16. Turbine Trip

a. Turbine Trip—Low Auto Stop Oil Pressure

The Turbine Trip—Low Auto Stop 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-8 setpoint, approximately 30% power, will not actuate a reactor trip. Three pressure switches monitor the Auto Stop oil pressure which interfaces with the Turbine Electrohydraulic Control System. 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 turbine control system. 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.

The LCO requires three channels of Turbine Trip—Low Auto Stop Oil Pressure to be OPERABLE in MODE 1 above P-8.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

16. Turbine Trip (continued)

a. Turbine Trip—Low Auto Stop Oil Pressure (continued)

Below the P-8 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 Auto Stop 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. Any turbine trip from a power level below the P-8 setpoint, approximately 30% power, 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 Auto Stop 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 LSSS for this Function is set to assure channel trip occurs when the associated stop valve is completely closed.

The LCO requires four Turbine Trip—Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-8. All four channels must trip to cause reactor trip.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

16. Turbine Trip (continued)

b. Turbine Trip—Turbine Stop Valve Closure (continued)

Below the P-8 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.

17. 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. This is a condition of acceptability for the LOCA. However, other 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. Therefore, a reactor trip is initiated every time an SI signal is present.

Allowable Values are not applicable to this Function. The SI input is provided by logic in the ESFAS. 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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

18. 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

18. Reactor Trip System Interlocks (continued)

a. Intermediate Range Neutron Flux, P-6 (continued)

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.

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 Impulse 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 Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

18. Reactor Trip System Interlocks (continued)

b. Low Power Reactor Trips Block, P-7 (continued)

(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 Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

Allowable Value is 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 increases above 10% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 30% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow—Low and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops on increasing power. The LCO requirement for this Function ensures that the Turbine Trip—Low Auto Stop Oil Pressure and Turbine Trip—Turbine Stop Valve Closure reactor trips are enabled above the P-8 setpoint. Above the P-8 setpoint, a turbine trip will

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

18. Reactor Trip System Interlocks (continued)

setpoint. Above the P-8 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-8 setpoint, to minimize the transient on the reactor. 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 approximately 30% power. On decreasing power, the reactor trip on low flow in any one 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-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below approximately 10% RTP on 3 of 4 channels, the nuclear instrument low power 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 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;

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

18. Reactor Trip System Interlocks (continued)

d. Power Range Neutron Flux, P-10 (continued)

- 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).

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.

e. Turbine Impulse Pressure, P-13

The Turbine Impulse Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. 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 Impulse Pressure, P-13 interlock to be OPERABLE in MODE 1.

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

19. 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 all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration. 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.

20. 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 19 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.

21. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 19 and 20) and Automatic Trip Logic (Function 21) ensures that means are provided to 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

21. Automatic Trip Logic (continued)

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 channels ensures that random failure of a single logic channel will not prevent reactor trip.

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 loop, per RCP, per SG, per train, etc., basis), then the Condition may be entered separately for each loop, RCP, SG, train, 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 must be immediately entered if applicable in the current MODE of operation.

BASES

ACTIONS (continued)

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.

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 and C.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;

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

- 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 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.

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.

The NIS power range detectors provide input to the Rod Control System and the SG Water Level Control System and, therefore, have a two-out-of-four trip logic. 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 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.

(continued)

ACTIONS

D.1.1, D.1.2, D.2.1, D.2.2, and D.3 (continued)

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 72 hour Completion Time and the 12 hour Frequency are consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)" for the long term monitoring requirement.

As an alternative to the above Actions, the unit may be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight hours are allowed to place the unit in MODE 3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit 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.

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;

(continued)

ACTIONS

E.1 and E.2 (continued)

- Overpower ΔT;
- Power Range Neutron Flux—High Positive Rate;
- Power Range Neutron Flux—High Negative 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.

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 both monitoring and protection Functions. If THERMAL POWER is greater than the

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

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 protection function 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 in MODE 2 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 both monitoring and protection Functions. With no intermediate range channels OPERABLE, suspending the introduction into the RCS of reactivity more positive than required to meet the SDM 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. 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 not result in reducing core reactivity below the required SDM. 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

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

Neutron Flux channels will be able to monitor the core power level and provides a protection function. 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.

Required Action G 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 or temperature control) 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 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 or temperature control) 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 rod not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both

(continued)

BASES

ACTIONS

<u>I.1</u> (continued)

source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition.

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

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 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. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour, are justified in Reference 7.

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

Condition K applies when the required number of OPERABLE Source Range Neutron Flux channels is not met in MODES 3, 4, or 5 with the Rod Control System is not capable of rod withdrawal. With the unit in this Condition, the NIS source range performs the monitoring function only. With less than the required number of source range channels OPERABLE, operations involving positive reactivity additions shall be suspended immediately.

The SDM must be verified within 1 hour and once every 12 hours thereafter as per SR 3.1.1.1, SDM verification. With no source range channels OPERABLE, the ability to monitor the core is severely reduced. Verifying the SDM within 1 hour allows sufficient time to perform the calculations and determine that the SDM requirements are met. The SDM must also be verified once per 12 hours thereafter to ensure that the core reactivity has not changed. Required Action K.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Time of within 1 hour and once per 12 hours are

(continued)

ACTIONS

K.1 and K.2 (continued)

based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.

Required Action K is modified by a Note which permits unit 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.

L.1 and L.2

Condition L applies to the following reactor trip Functions:

- Pressurizer Pressure—Low;
- Pressurizer Water Level—High;
- Reactor Coolant Flow—Low;
- 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, and Underfrequency RCPs 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 and RCP Breaker Position (Two Loops) trip Functions, placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel in the same loop to initiate a reactor trip. For the latter two trip Functions, 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. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. There is insufficient heat production to generate DNB conditions below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 7. An additional 6 hours is allowed

(continued)

BASES

ACTIONS

L.1 and L.2 (continued)

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.

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.

M.1 and M.2

Condition M applies to the RCP Breaker Position reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 72 hours. If the channel cannot be restored to OPERABLE status within the 72 hours, then THERMAL POWER must be reduced below the P-7 setpoint within the next 6 hours.

This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-7 setpoint because other RTS Functions provide core protection below the P-8 setpoint. The 72 hours allowed to restore the channel to OPERABLE status and the 6 additional hours allowed to reduce THERMAL POWER to below the P-7 setpoint are justified by a plant-specific risk assessment consistent with Reference 7.

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 by a plant-specific risk assessment consistent with Reference 7.

BASES

ACTIONS (continued)

N.1 and N.2

Condition N applies to Turbine Trip on Low Auto Stop 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 requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-8 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.

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.

O.1 and O.2

Condition O 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 O.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours (Required Action O.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 Completion Time of 6 hours (Required Action O.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.

P.1 and P.2

Condition P 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, 1 hour is allowed to

(continued)

BASES

ACTIONS

P.1 and P.2 (continued)

restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. 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. Placing the unit in MODE 3 results in Action C entry while RTB(s) are inoperable.

The Required Actions have been modified by three Notes. Note 1 allows one channel to be bypassed for up to 2 hours for surveillance testing, provided the other channel is OPERABLE. Note 1 applies to RTB testing that is performed independently from the corresponding logic train testing. For simultaneous testing of logic and RTBs, the 4 hour test time limit of Condition O applies. Note 2 allows one RTB to be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms if the other RTB train is OPERABLE. The 2 hour time limit is justified in Reference 7. Note 3 applies to RTB testing that is performed concurrently with the corresponding logic train testing. For concurrent testing of the logic and RTB, the 4 hour test time limit of Condition O applies. The 4 hour time limit is justified in Reference 7.

Q.1 and Q.2

Condition Q 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 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.

BASES

ACTIONS (continued)

R.1 and R.2

Condition R applies to the P-7, P-8, 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 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.

S.1 and S.2

Condition S 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 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 P.

The Completion Time of 48 hours for Required Action S.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.

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. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

<u>SR 3.3.1.1</u>

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 exceeds the power range channel output by more than +2% RTP, the power range channel 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 exceeds 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.

If the calorimetric is performed at part power (< 85% RTP), adjusting the power range channel indication in the increasing power direction will assure a reactor trip below the safety analysis limit (< 118% RTP). 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 power 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 (< 85% RTP). This action may introduce a non-conservative bias at higher power levels which may result in an NIS reactor trip above the safety analysis limit (> 118% RTP). The cause of the 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. The ultrasonic flow meter provides more accurate feedwater flow measurement than the existing venturis. Feedwater flow measurement from the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

ultrasonic flow meter may be used to compute the secondary side power calorimetric. If feedwater ultrasonic flow meter data is used for the calorimetric at reduced flow, the accuracy is also reduced however not as significantly as with the feedwater venturi data. 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 when: (1) the power range channel output is adjusted in the decreasing power direction due to a part power calorimetric below 85% RTP; or (2) for a post refueling startup. The evaluation of extended operation at part power 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 the enabling of the Power Range Neutron Flux—Low Setpoint and the Intermediate Range Neutron Flux reactor trips. Before the Power Range Neutron Flux—High bistables are reset to ≤ 109% RTP, a calorimetric must be performed and the power range channels must be adjusted such that the high flux bistables will trip at £ 109% RTP. Consideration must be given to calorimetric uncertainty, and its impact on decalibration of the power range channels.

The Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12 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 based on operating experience, equipment reliability, and plant risk and 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 it must be readjusted. The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. The adjustment is a recalibration of the upper and lower Power Range detectors to incorporate the results of the flux map.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

A Note clarifies that the Surveillance is required only if reactor power is ≥ 15% RTP and that 72 hours is allowed for performing the first Surveillance after reaching 15% RTP.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The 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 3.3.1.14. The test of the bypass breaker is a local shunt trip actuation. A Note has been added to indicate that this

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.4 (continued)

test must be performed on the bypass breaker. The local manual shunt trip of the RTB bypass shall be conducted immediately after placing the bypass breaker into service.

This test must be conducted prior to the start of testing on the RTS or maintenance on a RTB. This checks the mechanical operation of the bypass breaker.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.6

SR 3.3.1.6 is the performance of a TADOT. 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

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.

Regarding RCP Underfrequency Testing, it should be noted that test circuits have not been installed on Unit 1, therefore, such testing can only be performed on Unit 2.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.7

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The nominal trip setpoints must be within the Allowable Values specified in Table 3.3.1-1.

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.

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. 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 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, 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. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The 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 of the Frequencies prior to reactor startup and four hours after reducing power below P-10 and P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, 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) and "4 hours after reducing power below P-6" (applicable to source range 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 applies if the unit remains in the MODE of Applicability after the initial performances of prior to reactor startup and twelve and four hours after reducing power below P-10 or P-6, respectively. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source 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 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the time limit.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

Twelve hours and four hours are reasonable times 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 source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 12 and 4 hours, respectively. Verification of the surveillance is accomplished by observing the permissive annunciator windows on the Main Control board. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.9

SR 3.3.1.9 is a comparison 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, the channels are declared inoperable. This Surveillance is performed to verify the $f(\Delta I)$ input to the overtemperature ΔT Function.

Two notes modify SR 3.3.1.9. Note 1 indicates that the excore NIS channels shall be adjusted if the absolute difference between the incore and excore is ≥ 3%. Note 2 states that this Surveillance is required only if reactor power is ≥ 50% RTP and that 72 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. 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.

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.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists 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 plateau or preamp discriminator curves, evaluating those curves, and comparing those curves to the manufacturer's data. 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. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detector (RTD) sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

This test will verify the dynamic compensation for flow from the core to the RTDs. The OTΔT function is lead/lag compensated and the OPΔT function is rate/lag compensated.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.12 (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RTS interlocks. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS. 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The 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 undervoltage trip mechanism for the Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.14 (continued)

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This TADOT is performed prior to exceeding the P-8 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the frequency specified in the Surveillance Frequency Control program. 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-8 interlock.

SR 3.3.1.16

SR 3.3.1.16 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 Technical Requirements Manual (Ref. 8). 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 (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, with the resulting measured response time compared to the appropriate UFSAR response time as listed in the TRM. Alternately, the response time test can be performed with the time constants set to their nominal value, provided the required response

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

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.

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" (Ref. 10) 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" (Ref. 11) provides the basis and the 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.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

SR 3.3.1.16 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. Response of neutron flux signal portion of the channel time shall be measured from the detector or input of the first electronic component in the channel. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

REFERENCES

1. UFSAR, Chapter 7.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. RTS/ESFAS Setpoint Methodology Study (Technical Report EE-0116).
7. WCAP-10271-P-A, Supplement 1, Rev. 1, June 1990 and WCAP-14333-P-A, Rev. 1, October 1998.
8. Technical Requirements Manual.
9. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety Related Instrumentation."
10. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.
11. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," December 1995.

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.

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.

The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for ESFAS action to prevent exceeding acceptable limits such that the consequences of Design Basis Accidents (DBAs) will be acceptable. The Allowable Value is considered a limiting value such that a channel is OPERABLE if the setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). Note that, although a channel is "OPERABLE" under these circumstances, the ESFAS setpoint must be left adjusted to within the established calibration tolerance band of the ESFAS setpoint in accordance with the 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.

BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often 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 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.

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. These setpoints are defined in UFSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 15 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable 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.

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

BASES

BACKGROUND (continued)

Allowable Values and ESFAS Setpoints

The trip setpoints used in the bistables are summarized in Reference 6. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation 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. 5), the Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservative with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Value and ESFAS setpoints including their explicit uncertainties, is provided in the unit specific setpoint methodology study (Ref. 6) which incorporates all of the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the determination of each ESFAS setpoint and corresponding Allowable Value. The nominal ESFAS setpoint entered into the bistable 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 for the purpose of the COT. 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 bistable is considered OPERABLE.

The ESFAS setpoints are the values at which the bistables are set and is the expected value to be achieved during calibration. The ESFAS setpoint value ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as-left" setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., calibration tolerance uncertainties). The ESFAS setpoint value is therefore considered a "nominal" value (i.e., expressed as a value without inequalities) for the purposes of the COT and CHANNEL CALIBRATION.

Setpoints adjusted consistent with the requirements of the Allowable Value 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.

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BACKGROUND

Allowable Values and ESFAS Setpoints (continued)

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Table 3.3.2-1. 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.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of outputs from 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 bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations 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 decision logic matrix functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other

(continued)

BASES

BACKGROUND

Solid State Protection System (continued)

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 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 by the SLAVE RELAY TEST circuit, 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. For example, Pressurizer Pressure—Low Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. A channel is OPERABLE with a trip setpoint value outside its calibration tolerance band provided the trip setpoint "as-found" value does not exceed

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BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

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 unit conditions. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

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 or bypassed 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:

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.

   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 all auxiliary feedwater (AFW) pumps;

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1. Safety Injection (continued)

- Control room ventilation isolation; 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;
- Isolation of the control room to ensure habitability; and
- Enabling ECCS suction from the refueling water storage tank (RWST) switchover on low low RWST level to ensure continued cooling via use of the containment sump.

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.

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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1. Safety Injection (continued)

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.

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. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system manual initiation. 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.

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;
- LOCA; and
- Feed line break inside containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1. Safety Injection (continued)

c. Safety Injection—Containment Pressure—High (continued)

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 transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

Thus, 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.

d. Safety Injection—Pressurizer Pressure—Low 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1. Safety Injection (continued)

d. Safety Injection—Pressurizer Pressure—Low Low (continued)

Three channels are required to satisfy the requirements with a two-out-of-three logic. North Anna design utilizes dedicated protection and control channels, and only three protection channels are necessary to satisfy the protective requirements.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing 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.

e. Steam Line Pressure—High Differential Pressure Between Steam Lines

Steam Line Pressure—High Differential Pressure Between Steam Lines provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1. Safety Injection (continued)

e. Steam Line Pressure—High Differential Pressure Between Steam Lines (continued)

Steam Line Pressure—High Differential Pressure Between Steam Lines provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the requirements, with a two-out-of-three logic on each steam line.

With the transmitters located away from the steam lines, it is not possible for them to experience adverse environmental conditions during an SLB event. The trip setpoint reflects only steady state instrument uncertainties. Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

f. g. Safety Injection—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low or Coincident With Steam Line Pressure—Low

These Functions (1.f and 1.g) provide protection against the following accidents:

- SLB; and
- the inadvertent opening of an SG relief or an SG safety valve.

Two steam line flow channels per steam line are required OPERABLE for these Functions. The steam line flow channels are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1. Safety Injection (continued)

f. g. Safety Injection—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low or Coincident With Steam Line Pressure—Low (continued)

channel is not sufficient to cause initiation. High steam flow in two steam lines is acceptable in the case of a single steam line fault due to the fact that the remaining intact steam lines will pick up the full turbine load. The increased steam flow in the remaining intact lines will actuate the required second high steam flow trip. Additional protection is provided by Function 1.e, High Differential Pressure Between Steam Lines.

One channel of T_{avg} per loop and one channel of low steam line pressure per steam line are required OPERABLE. For each parameter, the channels for all loops or steam lines are combined in a logic such that two channels tripped will cause a trip for the parameter. The low steam line pressure channels are combined in two-out-of-three logic. Thus, the Function trips on one-out-of-two high flow in any two-out-of-three steam lines if there is one-out-of-one low low T_{avg} trip in any two-out-of-three RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-three steam lines. Since the accidents that this event protects against cause both low steam line pressure and low low T_{avg}, provision of one channel per loop or steam line ensures no single random failure can disable both of these Functions. The steam line pressure channels provide no control inputs. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate.

The Allowable Value for high steam flow is a linear function that varies with power level. The function is a ΔP corresponding to 42% of full steam flow between 0% and 20% load to 111% of full steam flow at 100% load. The nominal trip setpoint is similarly calculated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

1. Safety Injection (continued)

f. g. Safety Injection—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low or Coincident With Steam Line Pressure—Low (continued)

With the transmitters located inside the containment (T_{avg}) or near the steam lines (High Steam Flow), it is possible for them to experience adverse steady state environmental conditions during an SLB event. The trip setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-12) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This signal may be manually blocked by the operator when below the P-12 setpoint. Above P-12, this Function is automatically unblocked. This Function is not required OPERABLE below P-12 because the reactor is not critical, so steam line break is not a concern. SLB may be addressed by Containment Pressure High (inside containment) or by High Steam Flow in Two Steam Lines coincident with Steam Line Pressure—Low, for Steam Line Isolation, followed by High Differential Pressure Between Two Steam Lines, for SI. 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

The Containment Spray Systems (Quench Spray (QS) and Recirculation Spray (RS)) provide four 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 sump after a large break LOCA; and

4. Remove heat from containment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

2. Containment Spray Systems (continued)

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; and
- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the QS pumps and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the QS pumps and mixed with a sodium hydroxide solution from the chemical addition tank. When the RWST level reaches the low setpoint coincident with Containment Pressure—High High, the RS pumps receive a start signal. The outside RS pumps start immediately and the inside RS pumps start after a 120-second delay. Water is drawn from the containment sump through heat exchangers and discharged to the RS nozzle headers. When the RWST reaches the low low level setpoint, the Low Head Safety Injection pump suctions are shifted to the containment sump. Containment spray is actuated manually or by Containment Pressure—High High signal. RS is actuated manually or by RWST Level—Low coincident with Containment Pressure—High High.

a. Containment Spray—Manual Initiation

The operator can initiate containment spray at any time from the control room by simultaneously turning two containment spray actuation switches in the same train. Because an inadvertent actuation of containment spray could have such serious consequences, two switches must be turned simultaneously to initiate containment spray. There are two sets of two switches each in the control room.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

2. Containment Spray Systems (continued)

a. Containment Spray—Manual Initiation (continued)

Simultaneously turning the two switches in either set will actuate containment spray in both trains in the same manner as the automatic actuation signal. Two Manual Initiation switches in each train are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function. Note that Manual Initiation of containment spray also actuates Phase B containment isolation.

b. Containment Spray—Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy exists in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. 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 containment spray, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system manual initiation. 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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

2. Containment Spray Systems (continued)

c. Containment Spray—Containment Pressure

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Allowable Value reflects only steady state instrument uncertainties.

This is one of few Functions that requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, since the consequences of an inadvertent actuation of containment spray could be serious. Note that this Function also has the inoperable channel placed in bypass rather than trip to decrease the probability of an inadvertent actuation.

North Anna uses four channels in a two-out-of-four logic configuration and the Containment Pressure—High High Setpoint Actuates Containment Spray Systems. Since containment pressure is not used for control, this arrangement exceeds the minimum redundancy requirements. Additional redundancy is warranted because this Function is energize 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.

d. RWST Level—Low Coincident with Containment Pressure—High High

This signal starts the RS system to provide protection against a LOCA inside containment. The Containment Pressure—High High (ESFAS Function 2.c) signal aligns the RS system for spray flow delivery (e.g., opens isolation valves) but does not start the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

2. Containment Spray Systems (continued)

d. RWST Level—Low Coincident with Containment Pressure—High High (continued)

RS pumps. The RWST Level—Low coincident with Containment Pressure—High High provides the automatic start signal for the inside RS and outside RS pumps. Once the coincidence trip is satisfied, the outside RS pumps start immediately and the inside RS pumps start after a 120-second delay. The delay time is sufficient to avoid simultaneous starting of the RS pumps on the same emergency diesel generator. This ESFAS function ensures that adequate water inventory is present in the containment sump to meet the RS sump strainer functional requirements following a LOCA. The RS system is not required for SLB mitigation.

Automatic initiation of RS must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy exists in the primary and secondary systems to pose a threat to containment integrity due to overpressure conditions. The requirement for automatic initiation of RWST Level—Low to be operable in MODES 1, 2, and 3 is consistent with the operability requirements for Containment Pressure—High High. Manual initiation of the RS system is required in MODE 4, even though automatic initiation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. 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. An operator can initiate RS at any time from the control room by using the pump control switch. The manual function would be used only when adequate water inventory is present in the containment sump to meet the RS sump strainer functional requirements.

BASES

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 (CC) and instrument air (IA), at a relatively low containment pressure indicative of primary or secondary system leaks. A list of the process lines is provided in the Technical Requirements Manual (Ref. 9). 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 CC is required to support RCP operation, not isolating CC on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CC 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 logic. All process lines penetrating containment, with the exception of CC and IA, are isolated. CC is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and air or oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to reaching MODE 4.

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 CC and IA. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CC at the higher pressure does not pose a challenge to the containment boundary because the CC

(continued)

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

3. Containment Isolation (continued)

System is a closed loop inside containment. Although some system components do not meet all of the ASME Code requirements applied to the containment itself, the system is 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 CC and IA Systems design and Phase B isolation ensures the CC System is 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 logic, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure—High High, a large break LOCA or SLB must have occurred. RCP operation will no longer be required and CC to the RCPs is, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CC flow to the thermal barrier heat exchanger.

Manual Phase B Containment Isolation is accomplished by the same switches that actuate Containment Spray. When the two switches in either set are turned simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

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

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

3. Containment Isolation (continued)

a. Containment Isolation—Phase A Isolation (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 to support system 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 Systems, Function 2). The Containment Pressure trip of Phase B Containment Isolation is energized to trip in order to minimize the potential of spurious trips that may damage the RCPs.

(1) Phase B Isolation—Manual Initiation

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

3. Containment Isolation (continued)

b. Containment Isolation—Phase B Isolation (continued)

(2) Phase B Isolation—Automatic Actuation Logic and Actuation Relays

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 Containment Spray manual actuation switches.

Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system 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

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c 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 trip valves (MSTVs), inside or outside of containment, closure of the MSTVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSTVs, closure of the MSTVs terminates the accident.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

4. Steam Line Isolation (continued)

a. Steam Line Isolation—Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are two switches for each MSTV in the control room and either switch can initiate action to immediately close that MSTV. Following a SG tube rupture, the operator will isolate the main steam side (close the MSTV) of the ruptured SG. The LCO requires two channels to be OPERABLE for each MSTV.

b. Steam Line Isolation—Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

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 MSTVs 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 MSTVs in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment with the sensing line (high pressure side of the transmitter) located inside containment. Containment Pressure—Intermediate High High provides no input to any control functions. Thus, two OPERABLE channels are sufficient to satisfy protective requirements with one-out-of-two logic. However, for enhanced reliability, this Function was

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

4. Steam Line Isolation (continued)

c. Steam Line Isolation—Containment Pressure—Intermediate High High (continued)

designed with three channels and a two-out-of-three logic. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions, and the trip setpoint reflects only steady state instrument uncertainties.

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 MSTVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSTVs 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. e. Steam Line Isolation—High Steam Flow in Two Steam Lines Coincident with T_{avg}—Low Low or Coincident With Steam Line Pressure—Low

These Functions (4.d and 4.e) provide closure of the MSTVs during an SLB or inadvertent opening of an SG relief or a safety valve, to maintain at least one unfaulted SG as a heat sink for the reactor and to limit the mass and energy release to containment.

These Functions were discussed previously as Functions 1.f. and 1.g.

These Functions must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines unless all MSTVs are closed and de-activated. These Functions are 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.

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

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.

The Function is actuated when the level in any SG exceeds the high high setpoint, and performs the following functions:

- Trips the main turbine;
- Trips the MFW pumps;
- Initiates feedwater isolation by closing the Main Feedwater Isolation Valves (MFIVs); and
- Shuts the MFW regulating valves and their associated bypass valves.

This Function is actuated by SG Water Level—High High, or by an SI signal. In the event of SI, the MFW System is automatically secured and isolated and the AFW System is automatically started. The SI signal was discussed previously.

a. Turbine Trip and Feedwater Isolation—Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Turbine Trip and Feedwater Isolation—Steam Generator Water Level—High High (P-14)

This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments provide input to the SG Water Level Control System. The SG Water Level—High High trip is provided from the narrow range instrumentation span from each SG.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

5. Turbine Trip and Feedwater Isolation (continued)

b. Turbine Trip and Feedwater Isolation—Steam Generator Water Level—High High (P-14) (continued)

North Anna has only three channels that are shared between protection and control functions and justification is provided in NUREG-1218 (Ref. 7).

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. 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.

Turbine Trip and Feedwater Isolation Functions must be OPERABLE in MODES 1, 2, and 3 when the MFW System is in operation and the turbine generator may be in operation. These functions are not required to be OPERABLE in MODES 2 and 3 when all MFW pump discharge valves or all MFIVs, MFRVs, and associated bypass valves are closed and de-activated or isolated by a closed manual valve. 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

6. Auxiliary Feedwater (continued)

Emergency condensate storage tank (ECST). The AFW System is aligned so that upon a pump start, flow is initiated to the respective SG immediately.

a. Auxiliary Feedwater—Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater—Steam Generator Water Level—Low Low

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. SG Water Level—Low Low provides input to the SG Level Control System. Three protection channels are necessary to satisfy the protective requirements. These channels are shared between protection and control functions and justification is provided in Reference 7.

With the transmitters (d/p cells) located inside containment and thus 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.

d. Auxiliary Feedwater—Loss of Offsite Power

A loss of offsite power to the transfer buses may be accompanied by a loss of reactor coolant pumping power and the subsequent need for some method of decay heat removal. The loss of offsite power is

(continued)

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

6. Auxiliary Feedwater (continued)

d. Auxiliary Feedwater—Loss of Offsite Power (continued)

detected by a voltage drop on each transfer bus. Loss of power to the transfer bus will start all AFW pumps to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

Functions 6.a through 6.d must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level—Low Low in any SG will cause all AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. 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 RCS Loop(s) 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.

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. Motor driven MFW pumps are equipped with a breaker position sensing device. An open supply breaker indicates that the pump is not running. Two OPERABLE channels per pump satisfy redundancy requirements with one-out-of-two logic on each MFW pump. A trip of all MFW pumps starts the motor driven and turbine driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Function 6.e must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is 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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

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 sump. The low head safety injection (LHSI) pumps and inside and outside recirculation spray pumps draw the water from the containment sump, the LHSI pumps pump the water back into the RCS. The Inside and Outside Recirculation Spray pumps circulate water through the heat exchangers to the spray rings and supplies water to the containment sump. Switchover from the RWST to the containment sump must occur before the RWST empties to prevent damage to the LHSI 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.

a. Automatic Switchover to Containment Sump—Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Automatic Switchover to Containment Sump—Refueling Water Storage Tank (RWST) Level—Low Low Coincident With Safety Injection

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. A low low level 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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

7. Automatic Switchover to Containment Sump (continued)

b. Automatic Switchover to Containment Sump—Refueling Water Storage Tank (RWST) Level—Low Low Coincident With Safety Injection (continued)

The RWST—Low 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 high limit also ensures adequate water inventory in the containment sump to provide ECCS pump suction.

The transmitters are located in an area not affected by HELBs or post accident high radiation. Thus, they will not experience any adverse environmental conditions and the Allowable Value reflects only steady state instrument uncertainties.

Automatic switchover occurs only if the RWST low low level 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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

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 are open. Once the P-4 interlock is enabled, automatic SI reinitiation is blocked after a 60 second time delay. This Function allows operators to take manual control of SI systems after the initial phase of injection is complete. Once SI is blocked, automatic actuation of SI cannot occur until the RTBs have been manually closed, resetting the P-4 interlock. The functions of the P-4 interlock are:

Function	Purpose	Required MODES
Isolate MFW regulating valves with coincident low T_{avg}	Feedwater isolation	1, 2
Trip the main turbine	Prevents excessive cooldown, thereby Condition II event does not propagate to Condition III event	1, 2

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

8. Engineered Safety Feature Actuation System Interlocks (continued)

a. Engineered Safety Feature Actuation System Interlocks—Reactor Trip, P-4 (continued)

Function	Purpose	Required MODES
Prevent automatic reactuation of SI after a manual reset of SI	Allows alignment of ECCS for recirculation mode, prevents subsequent inadvertent alignment to injection mode by auto SI	1, 2, 3

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

8. Engineered Safety Feature Actuation System Interlocks (continued)

a. Engineered Safety Feature Actuation System Interlocks—Reactor Trip, P-4 (continued)

Function	Purpose	Required MODES
Reset high steam flow setpoint to no-load value 1. SI-High Steam flow in Two Steam Lines Coincident With Steam Line Pressure—Low 2. SI—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low 3. Steam Line Isolation—High Steam Flow in Two Steam Lines Coincident With Steam Line Pressure-Low 4. Steam Line Isolation—High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low	Ensures setpoint is reset to low/zero power reference value following plant trip, regardless of turbine first stage pressure indication	1, 2, 3 (function not required if MSTVs are closed and deactivated)

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

8. Engineered Safety Feature Actuation System Interlocks (continued)

a. Engineered Safety Feature Actuation System Interlocks—Reactor Trip, P-4 (continued)

Function	Purpose	Required MODES
Prevent opening of the MFW regulating valves if they were closed on SI or SG Water Level —High High	Seal-in feedwater isolation to prevent inadvertent feeding of depressurized SG	1, 2, 3

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 core power. Addition of feedwater to a steam generator associated with a steamline or feedline break could result in excessive containment building pressure. 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.

The turbine trip Function is explicitly assumed in the non-LOCA analysis since it is an immediate consequence of the reactor trip Function. Block of the auto SI signals is required to support long-term ECCS operation in the post-LOCA recirculation mode.

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 an Allowable Value.

This Function must be OPERABLE in MODES 1, 2, and 3, as noted above, when the reactor may be critical or approaching criticality or support of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

8. Engineered Safety Feature Actuation System Interlocks (continued)

a. Engineered Safety Feature Actuation System Interlocks—Reactor Trip, P-4 (continued)

auto SI block function is required. This Function does not have to be OPERABLE in MODES 4, 5, or 6 because the main turbine and the MFW System are not required to be in operation.

b. Engineered Safety Feature Actuation System Interlocks—Pressurizer Pressure, P-11

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of SI. With two-out-of-three pressurizer pressure channels (discussed previously) less than the P-11 setpoint, the operator can manually block the Pressurizer Pressure—Low Low SI signal. Additionally, the P-11 signal blocks the automatic opening of the pressurizer power operated relief valves (PORVs).

With two-out-of-three pressurizer pressure channels above the P-11 setpoint, the Pressurizer Pressure—Low Low SI signal is automatically enabled. The operator can also enable this function by use of the respective manual reset switches. The automatic opening capability for the pressurizer PORVs is reinstated above the P-11 setpoint. The ECCS accumulator isolation valves will receive an automatic open signal when pressurizer pressure exceeds the P-11 setpoint. The Allowable Value 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. 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 reinstates SI on High Steam Flow Coincident

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

8. Engineered Safety Feature Actuation System Interlocks (continued)

c. Engineered Safety Feature Actuation System Interlocks—T_{avg}—Low Low, P-12 (continued)

With Steam Line Pressure—Low or Coincident With T_{avg}—Low Low. On decreasing reactor coolant temperature, the P-12 interlock allows the operator to manually block SI on High Steam Flow Coincident With Steam Line Pressure—Low or Coincident with T_{avg}—Low Low. On a decreasing temperature, the P-12 interlock also provides a blocking signal to the Steam Dump System to prevent an excessive cooldown of the RCS due to a malfunctioning Steam Dump System.

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.

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. 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 have an accident.

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

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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.

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 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.

(continued)

BASES

ACTIONS (continued)

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; and
- Phase A Isolation.

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 isolation, failure of one or both channels in one train renders the train inoperable. The manual initiation for Phase B Containment isolation is provided by the containment spray manual switches. 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 Function, 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 (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.

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ACTIONS (continued)

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;
- Phase B Isolation; and
- Automatic Switchover to Containment Sump.

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 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 Reference 8 that 4 hours is the average time required to perform channel surveillance.

D.1, D.2.1, and D.2.2

Condition D applies to:

- Containment Pressure—High;
- Pressurizer Pressure—Low Low;
- Steam Line Differential Pressure—High;

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ACTIONS

D.1, D.2.1, and D.2.2 (continued)

- High Steam Flow in Two Steam Lines Coincident With T_{avg}—Low Low or Coincident With Steam Line Pressure—Low;
- Containment Pressure—Intermediate High High;
- SG Water Level—Low Low;
- SG Water Level—High High (P-14); and
- RWST Level—Low Coincident With Containment Pressure High High.

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.

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 72 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 12 hours allowed for testing, are justified in Reference 8.

E.1, E.2.1, and E.2.2

Condition E applies to:

- Containment Spray Containment Pressure—High High; and

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E.1, E.2.1, and E.2.2 (continued)

- 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 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 additional 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 8.

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ACTIONS (continued)

F.1, F.2.1, and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation;
- Loss of Offsite Power; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. For the Loss of Offsite Power Function, this action recognizes the lack of manual trip provision for a failed channel. 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.

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 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

(continued)

BASES

ACTIONS

G.1, G.2.1, and G.2.2 (continued)

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 (Ref. 8) assumption that 4 hours is the average time required to perform channel surveillance.

H.1 and H.2

Condition H applies to the AFW pump start on trip of all MFW pumps.

This action addresses the train orientation of the SSPS for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. 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 8.

I.1, I.2.1, and I.2.2

Condition I applies to:

- RWST Level—Low Low Coincident with Safety Injection.

RWST Level—Low 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

(continued)

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ACTIONS

I.1, I.2.1, and I.2.2 (continued)

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 high). The 72 hour Completion Time is justified in a plant-specific risk assessment, consistent with Reference 8. 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 functions noted above.

The Required Actions are modified by a Note that allows placing a second channel in the bypass condition for up to 12 hours for surveillance testing. The total of 78 hours to reach MODE 3 and 12 hours for a second channel to be bypassed is acceptable based on the results of a plant-specific risk assessment, consistent with Reference 8.

J.1, J.2.1, and J.2.2

Condition J 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. The verification that the interlocks are in their proper state may be performed via the Control Room permissive status lights. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown

(continued)

BASES

ACTIONS

J.1, J.2.1, and J.2.2 (continued)

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 to clarify 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 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.

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. 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 based on operating experience, equipment reliability, and plant risk and 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. 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. This verifies that the logic modules are OPERABLE. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.4 (continued)

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. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least one per refueling interval with applicable extensions.

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.

The COT for the Containment Pressure Channel includes exercising the transmitter by applying either a vacuum or pressure to the appropriate side of the transmitter.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.5

SR 3.3.2.5 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. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that allows an exception for testing of relays which could induce a unit transient, an inadvertent reactor trip or ESF actuation, or cause the inoperability of two or more ESF components.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of the Loss of Offsite Power Function. The Function is tested up to, and including, the master relay coils. 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least one per refueling interval with applicable extensions.

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT. This test is a check of the Manual Actuation Functions, AFW pump start on trip of all MFW pumps and the P-4 interlock Function, including turbine trip, automatic SI block, and seal-in of feedwater isolation by SI.

Each Manual Actuation Function is tested up to, and including, the master relay coils. 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least one per refueling interval with applicable extensions. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The turbine trip (P-4) is independently verified for both trains. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. However, the P-4 input signals to SSPS actuation logic are normally tested in conjunction with RTB testing under SR 3.3.1.4 on a 31-day staggered test basis.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.2.7 (continued)

The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation or interlock Functions. The manual initiation 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. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 Technical Requirements Manual (Ref. 9).

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).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

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 with the resulting measured response time compared to the appropriate UFSAR response time. 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.

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" (Ref. 10) 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" (Ref. 11) provides the basis and the 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 1005 psig in the SGs.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 7.

3. UFSAR, Chapter 15.

4. IEEE-279-1971.

5. 10 CFR 50.49.

6. RTS/ESFAS Setpoint Methodology Study (Technical Report EE-0116).

7. NUREG-1218, April 1988.

8. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990 and WCAP-14333-P-A, Rev. 1, October 1998.

9. Technical Requirements Manual.

10. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

11. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," December 1995.

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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 Reference 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 two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 as Type A and Category I variables.

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. Primary information is defined as information that is essential for the direct accomplishment of the specific safety functions; it does not include those variables that are associated with contingency actions that may also be identified in written procedures.

(continued)

BASES

BACKGROUND (continued)

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
- 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 plant specific Regulatory Guide 1.97 analyses (Ref. 1). This report identifies the plant specific Type A and Category I variables and provides justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to pre-planned 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- 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.

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 plant 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.

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 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.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

The exception to the two channel requirement is Containment Isolation Valve (CIV) Position indication for a CIV with only one installed position indication. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. In this configuration, this is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of a passive valve, or via system boundary status. Some single CIVs have two installed control room indication channels and both are required to be

(continued)

BASES

LCO (continued)

OPERABLE for compliance with PAM instrumentation requirements. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Table 3.3.3-1 lists all Type A and Category I variables identified by the plant specific Regulatory Guide 1.97 analyses (Ref. 1).

Reference 1, Technical Report PE-0013, North Anna Power Station Response to Regulatory Guide 1.97 and Reference 4, Technical Requirements Manual (TRM) Section 3.3.9 - Regulatory Guide (RG) 1.97 Instrumentation, provide specific design and qualification requirements for RG 1.97 instrumentation.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1, 2. Power Range and Source Range Neutron Flux

Power Range and Source Range Neutron Flux indication is provided to verify reactor shutdown. This indication is provided by the Gammametric channels. The two ranges are necessary to cover the full range of flux that may occur post accident.

Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

3, 4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Ranges)

RCS Hot and Cold Leg Temperature wide range indications are Category I variables provided for verification of core cooling and long term surveillance.

The 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.

The channels provide indication over a range of 0°F to 700°F.

BASES

LCO (continued)

5. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Category I variable provided for verification of core cooling and RCS integrity long term surveillance.

RCS pressure is used to verify closure of 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 safety injection (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;
- to make a decision on operation of reactor coolant pumps (RCPs); 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.

Another use of RCS pressure is to determine whether to operate the pressurizer heaters.

(continued)

LCO

5. Reactor Coolant System Pressure (Wide Range) (continued)

RCS pressure is a Type A variable because the operator uses this indication to monitor subcooling margin during 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.

6. Inadequate Core Cooling Monitoring (ICCM) System

The ICCM consists of three functional subsystems. Each subsystem is composed of two instrumentation trains. The three subsystems of ICCM are: the Reactor Vessel Level Instrumentation System (RVLIS); Core Exit Temperature Monitoring (CETM); and Subcooling Margin Monitor (SMM). The functions provided by the subsystems are discussed below.

6.a Reactor Vessel Level Instrumentation System

RVLIS is provided for verification and long term surveillance of core cooling. It is also used to determine reactor coolant inventory adequacy.

The RVLIS provides a measurement of the collapsed liquid level above the upper core 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 an indication of the water inventory.

6.b Reactor Coolant System Subcooling Margin Monitor

The RCS SMM is a Category I variable provided for verification of core cooling. The SMM subsystem calculates the margin to saturation for the RCS from inputs of wide range RCS pressure transmitters and the average of the five highest temperature core exit thermocouples. The two trains of SMM receive inputs from separate trains of pressure transmitters and core exit thermocouples (CETs).

(continued)

BASES

LCO

6.b <u>Reactor Coolant System Subcooling Margin Monitor</u> (continued)

The SMM indicators are redundant to the information provided by the RCS hot and cold leg temperature and RCS wide range pressure indicators. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiating of SI if it has been secured. RCS subcooling margin is also used for unit stabilization, cooldown control, and RCP trip criteria. The SMM indicates the degree of subcooling from -35°F (superheated) to +200°F (subcooled).

6.c <u>Core Exit Temperature Monitoring</u>

CETM is provided for verification and long term surveillance of core cooling. Two OPERABLE CETs per channel are required in each core quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Two sets of two thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient. Monitoring of the CETs is available through the Inadequate Core Cooling Monitor. Different CETs are connected to their respective channel, so a single CET failure does not affect both channels. The following CET indication is provided in the control room:

- Five hottest thermocouples (ranked from highest to lowest);
- Maximum, Average, and Minimum temperatures for each quadrant; and
- Average of the five high thermocouples.

7. <u>Containment Sump Water Level (Wide Range)</u>

Containment Sump Water Level is provided for verification and long term surveillance of RCS integrity.

Containment Sump Water Level is used for accident diagnosis.

BASES

LCO (continued)

8, 9. Containment Pressure and Containment Pressure Wide Range

Containment Pressure and Containment Pressure Wide Range are provided for verification of RCS and containment OPERABILITY.

Containment Pressure channels are used to verify Safety Injection (SI) initiation and Phase A isolation on a Containment Pressure—High signal. These channels are also used to verify closure of the Main Steam Trip Valves on a Containment Pressure—Intermediate High High signal. The Containment Pressure channels are also used to verify initiation of Containment Spray and Phase B isolation on a Containment Pressure—High High signal.

10. Penetration Flow Path Containment Isolation Valve Position

CIV Position is provided for verification of Containment OPERABILITY, and Phase A and Phase B isolation.

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. For containment penetrations with only one active CIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE for penetration flow paths with only one installed control room indication channel. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. Some single CIVs have two installed control room indication channels and both are required to be OPERABLE for compliance with PAM instrumentation requirements. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Note (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.

BASES

LCO (continued)

11. Containment Area Radiation (High Range)

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 determine if adverse containment conditions exist.

12. Deleted

13. Pressurizer Level

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.

14, 15. Steam Generator Water Level (Wide and Narrow Ranges)

SG Water Level is provided to monitor operation of decay heat removal via the SGs. Both wide and narrow ranges are Category I indications of SG level. The wide range level covers a span of +7 to -41 feet from nominal full load water level. The narrow range instrument covers from +7 to -5 feet of nominal full load water level.

The level signals are inputs to the unit computer, control room indicators, and the Auxiliary Feedwater System.

SG Water Level is used to:

- identify the affected SG following a tube rupture;
- 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 SGTR); and
- verify unit conditions for termination of SI.

BASES

LCO

14, 15. <u>Steam Generator Water Level (Wide and Narrow Ranges)</u> (continued)

Operator action is based on the control room indication of SG level. The RCS response during a design basis small break LOCA depends on the break size. For a certain range of break sizes, a secondary heat sink is necessary to remove decay heat. Narrow range level is a Type A variable because the operator must manually raise and control SG level.

16. <u>Emergency Condensate Storage Tank (ECST) Level</u>

ECST Level is provided to ensure water supply for auxiliary feedwater (AFW). The ECST provides the ensured safety grade water supply for the AFW System. Inventory is monitored by a 0% to 100% level indication and ECST Level is displayed on a control room indicator.

The DBAs that require AFW are the loss of offsite electric power, loss of normal feedwater, SGTR, steam line break (SLB), and small break LOCA.

The ECST is the initial source of water for the AFW System. However, as the ECST is depleted, manual operator action is necessary to replenish the ECST.

17. <u>Steam Generator Pressure</u>

SG pressure is a Category I variable and provides an indication of the integrity of a steam generator. This indication can provide important information in the event of a faulted or ruptured steam generator.

18. <u>High Head Safety Injection (HHSI) Flow</u>

Total HHSI flow to the RCS cold legs is a Type A variable and provides an indication of the total borated water supplied to the RCS. For the small break LOCA, HHSI flow may be the only source of borated water that is injected into the RCS. Total HHSI flow is a Type A variable because it provides an indication to the operator for the RCP trip criteria.

BASES

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.

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 immediate initiation of actions in Specification 5.6.6, which requires a written report to be submitted to the NRC within the following 14 days. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

BASES

ACTIONS (continued)

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.

D.1 and D.2

If the Required Action and associated Completion Time of Condition D is not met 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 in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1 with the exception that SR 3.3.3.3 is not required to be performed on containment isolation valve position indication. SR 3.3.3.4 is required for the containment isolation valve position indication.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

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. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

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

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.2

Not Used

SR 3.3.3.3

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 a Note that excludes neutron detectors. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the CET sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.4

SR 3.3.3.4 is the performance of a TADOT of containment isolation valve position indication. This TADOT is performed every 18 months. The test shall independently verify the OPERABILITY of containment isolation valve position indication against the actual position of the valves.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Technical Report PE-0013.

2. Regulatory Guide 1.97, May 1983.

3. NUREG-0737, Supplement 1, "TMI Action Items."

4. Technical Requirements Manual

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation 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) power operated relief valves (PORVs) 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 at the auxiliary shutdown panel, and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the auxiliary shutdown panel. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the remote shutdown control and instrumentation 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.

The criteria governing the design and specific system requirements of the Remote Shutdown System are located in Reference 1.

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

BASES

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to maintain the unit in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Table B 3.3.4-1.

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

- Core reactivity control (long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the SG PORVs; and
- RCS inventory control via charging flow.

A Function of a Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the Remote Shutdown System Function are OPERABLE. In some cases, Table B 3.3.4-1 may indicate that the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information or control sources is OPERABLE.

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits 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.

BASES

ACTIONS

A Remote Shutdown System function is inoperable when the function is not accomplished by at least one designed Remote Shutdown System channel that satisfies the OPERABILITY criteria for the channel's Function. These criteria are outlined in the LCO section of the Bases.

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)/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 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.

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 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

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 channels which are normally energized.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.2

SR 3.3.4.2 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 remote shutdown panel and the local control stations. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.3

CHANNEL CALIBRATION is a complete check of the 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 (RTD) sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 3.

Table B 3.3.4-1 (page 1 of 1)
Remote Shutdown System Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. Reactivity Control	
a. Boric Acid Pump controls	1
2. Reactor Coolant System (RCS) Pressure Control	
a. Pressurizer Pressure indications	1
b. Pressurizer Heater controls	1
3. Decay Heat Removal via Steam Generators (SGs)	
a. RCS T_{avg} Temperature indication	1 loop
b. AFW Pump and Valve controls	1
c. SG Pressure indication	1
d. SG Level (Wide Range) indication	1
e. SG Power Operated Relief Valve controls	1
f. AFW Discharge Header Pressure indication	1
g. Emergency Condensate Storage Tank Level indication	1
4. RCS Inventory Control	
a. Pressurizer Level indication	1
b. Charging Pump controls	1
c. Charging Flow control	1

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Emergency Diesel Generator (EDG) Start Instrumentation

BASES

BACKGROUND

The EDGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs on the emergency buses. There are two required LOP start signals for each 4.16 kV emergency bus.

Undervoltage relays are provided on each 4160 V Class 1E bus for detecting a loss of bus voltage or a sustained degraded voltage condition. The relays are combined in a two-out-of-three logic to generate a LOP signal. A loss of voltage start of the EDG is initiated when the voltage is less than 74% of rated voltage and lasts for approximately 2 seconds. A degraded voltage start of the EDG is produced when the voltage is less than 90% of rated voltage sustained for approximately 56 seconds. The time delay for the degraded voltage start signal is reduced to approximately 7.5 seconds with the presence of a Safety Injection signal for the H and J bus on this unit.

One 4160 VAC bus from the other unit is needed to support operation of each required Service Water (SW) pump, Main Control Room/Emergency Switchgear Room (MCR/ESGR) Emergency Ventilation System (EVS) fan, Auxiliary Building central exhaust fan, and Component Cooling Water (CC) pump. SW, MCR/ESGR EVS, Auxiliary Building central exhaust system, and CC are shared systems.

The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for Engineered Safety Features Actuation System (ESFAS) action to prevent exceeding acceptable limits such that the consequences of Design Basis Accidents (DBAs) will be acceptable. The Allowable Value is considered a limiting value such that a channel is OPERABLE if the setpoint is found not to exceed the Allowable Value 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

(continued)

BASES

BACKGROUND (continued)

in accordance with uncertainty assumptions stated in the referenced setpoint methodology, (as-left-criteria) and confirmed to be operating with the statistical allowances of the uncertainty terms assigned.

Allowable Values and LOP EDG Start Instrumentation Setpoints

The trip setpoints are summarized in Reference 3. The selection of the Allowable Values is such that adequate protection is provided when all sensor and processing time delays are taken into account.

Setpoints adjusted consistent with the requirement of the Allowable Value ensure that the consequences of accidents 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 SR 3.3.5.2. Nominal trip setpoints are also specified in the unit specific setpoint calculations and listed in the Technical Requirements Manual (TRM) (Ref. 2). The 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 calculation (Ref. 3).

APPLICABLE SAFETY ANALYSES

The LOP EDG start 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 ESFAS.

Accident analyses credit the loading of the EDG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual EDG start has historically been associated with the ESFAS actuation. The EDG loading has been included in the delay time associated with each safety system component requiring EDG supplied power following a loss of offsite power. The analyses assume a non-mechanistic

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

EDG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP EDG start instrumentation, in conjunction with the ESF systems powered from the EDGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 5, 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 EDG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate EDG loading and sequencing delay if applicable.

The LOP EDG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP EDG start instrumentation requires that three channels per bus of both the loss of voltage and degraded voltage Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP EDG start instrumentation supports safety systems associated with the ESFAS. This is associated with the requirement of LCO 3.3.5.a for this unit's H and J buses. LCO 3.3.5.b specifies that for a required H and/or J bus on the other unit that is needed to support a required shared component for this unit, the LOP EDG start instrumentation for the required bus must be OPERABLE. The other unit's required H and/or J bus are required to be OPERABLE to support the SW, MCR/ESGR EVS, Auxiliary Building central exhaust, and CC functions needed for this unit. These Functions share components, pumps, or fans, which are electrically powered from both units. A channel is OPERABLE with a trip setpoint value outside its calibration tolerance band 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 trip setpoint. A trip setpoint may be set more conservative than the trip setpoint specified in the TRM (Ref. 2) as necessary in response to unit conditions. In MODES 5 or 6, the three channels must be OPERABLE whenever the associated EDG is required to be OPERABLE to ensure that the automatic start of

(continued)

BASES

LCO (continued)	the EDG is available when needed. Loss of the LOP EDG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the EDG 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.
APPLICABILITY	The LOP EDG Start 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 or 6 is required whenever the required EDG must be OPERABLE so that it can perform its function on a LOP or degraded power to the 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 listed in the LCO and for each emergency bus. 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 for the associated emergency bus.

A.1

Condition A applies to the LOP EDG start Function with one loss of voltage or degraded voltage channel per bus inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 72 hours. A plant-specific risk assessment, consistent with Reference 4,

(continued)

BASES

ACTIONS

A.1 (continued)

was performed to justify the 72 hour Completion Time. With a channel in trip, the LOP EDG start instrumentation channels are configured to provide a one-out-of-two logic to initiate a trip of the incoming offsite power.

A Note is added to allow bypassing an inoperable channel for up to 12 hours for surveillance testing of other channels. A plant-specific risk assessment, consistent with Reference 4, was performed to justify the 12 hour time limit. This allowance is made where bypassing the channel does not cause an actuation and where normally, excluding required testing, two other channels are monitoring that parameter.

The specified Completion Time and time allowed for bypassing one channel are reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

B.1

Condition B applies when more than one loss of voltage or more than one degraded voltage channel on an emergency bus is inoperable.

Required Action B.1 requires restoring all but one 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 an LOP start occurring during this interval.

C.1

Condition C applies to each of the LOP EDG start Functions when the Required Action and associated Completion Time for Condition A or B 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 EDG made inoperable by failure of the LOP EDG start 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 for channels required by LCO 3.3.5.a and LCO 3.3.5.b. 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at an 18 month frequency with applicable extensions. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to the loss of voltage and degraded voltage relays for the 4160 VAC emergency buses, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION. Each train or logic channel shall be functionally tested up to and including input coil continuity testing of the ESF slave relay. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION for channels required by LCO 3.3.5.a and LCO 3.3.5.b.

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 shown in Reference 1.

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 verification of degraded voltage with a SI signal is not required by LCO 3.3.5.b.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2 (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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 for channels required by LCO 3.3.5.a and LCO 3.3.5.b. Response Time testing acceptance criteria are included in the TRM (Ref. 2).

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).

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 with the resulting measured response time compared to the appropriate TRM response time. 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.

Response time may be verified by actual response time test 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.

Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Section 8.3.

2. Technical Requirements Manual.

3. RTS/ESFAS Setpoint Methodology Study (Technical Report EE-0116).

4. WCAP 14333-P-A, Rev. 1, October 1998.

5. UFSAR, Chapter 15.

B 3.3 INSTRUMENTATION

B 3.3.6 Main Control Room/Emergency Switchgear Room (MCR/ESGR) Envelope Isolation Actuation Instrumentation

BASES

BACKGROUND

The MCR/ESGR Envelope Isolation function provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity. During normal operation, the MCR and Relay Room Air Condition System provides unfiltered makeup air and cooling. Upon receipt of an MCR/ESGR Envelope Isolation actuation signal from either unit Safety Injection (SI), High Radiation or manual, the Unit 1 and 2 control room normal ventilation intake and exhaust ducts are isolated to prevent unfiltered makeup air from entering the control room. In addition to MCR/ESGR envelope isolation, an SI signal also automatically starts the affected units MCR/ESGR EVS fans to provide filtered recirculated air within the MCR/ESGR envelope. The Fuel Building High Radiation or manual initiation starts both units' available EVS train fans in the recirculation mode. Manual operator action is required to align the MCR/ESGR EVS to provided filtered makeup air. The MCR/ESGR EVS is described in the Bases for LCO 3.7.10, "Main Control Room/Emergency Switchgear Room Emergency Ventilation System."

There are four independent and redundant trains of manual actuation instrumentation for the MCR/ESGR Envelope Isolation. Each manual actuation train consists of two actuation switches (channels), and the interconnecting wiring to the actuation circuitry. Only one switch (channel) per train and two of the four trains are required for the system to maintain independence and redundancy.

The MCR/ESGR Envelope Isolation is actuated on a SI signal from either unit, a Fuel building High Radiation signal or manual switches in the MCR. The Safety Injection 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 MCR/ESGR Envelope Isolation actuation on a SI signal acts to automatically terminate the supply of

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BASES

APPLICABLE SAFETY ANALYSES (continued)

unfiltered outside air to the control room and initiate filtration in the recirculation mode. Manual actions are required to align the MCR/ESGR EVS to provide filtered make up air to the MCR/ESGR envelope.

The safety analysis for a loss of coolant accident in MODES 1-4 assumes automatic isolation of the MCR/ESGR envelope on a SI signal and manual initiation of filtered outside air flow within 1 hour. No credit is taken for filtered recirculation or pressurization provided by the MCR/ESGR EVS. The safety analysis for a fuel handling accident (FHA) assumed manual isolation of the MCR/ESGR envelope and manual initiation or positioning of the MCR/ESGR EVS to supply filtered air flow within 1 hour. For the remaining design basis accidents, MCR/ESGR envelope isolation is not assumed. Normal ventilation inflow with 500 cfm of additional unfiltered inleakage is assumed.

The accident analysis assumes normal ventilation during a toxic gas or smoke incident. The MCR/ESGR envelope isolation is not required to mitigate the consequences of these events.

The MCR/ESGR EVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that instrumentation necessary to initiate isolation of the MCR/ESGR envelope is OPERABLE.

1. Manual Initiation

   The LCO requires one channel per train and two trains OPERABLE. The operator can initiate the MCR/ESGR isolation at any time by using any one of the two switches in a train from the control room. This action will cause actuation of components in the same manner as the automatic actuation signal.

   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 train consists of two switches (channels) and the interconnecting wiring to the actuation circuitry.

BASES

LCO (continued)

2. Safety Injection

Refer to LCO 3.3.2 Function 1 for all initiating Functions and requirements.

APPLICABILITY

The MCR/ESGR Envelope Isolation Functions must be operable in MODES 1, 2, 3, and 4 and during the movement of recently irradiated fuel assemblies to provide the required MCR/ESGR envelope isolation 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 300 hours) is taking place, there are no requirements for MCR/ESGR EVS instrumentation OPERABILITY consistent with the safety analyses assumptions applicable in these MODES.

In addition, the manual channels are required OPERABLE when moving recently irradiated fuel.

ACTIONS

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 3.3.6-1 in the accompanying LCO. The Completion Time(s) of the inoperable 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.

A.1

Condition A applies to the Manual Function of the MCR/ESGR EVS.

If one train 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 MCR/ESGR EVS is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10. If the train cannot be restored to OPERABLE status, the normal ventilation to the MCR/ESGR envelope must be isolated. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

BASES

ACTIONS (continued)

B.1

Condition B applies to the failure of two MCR/ESGR Envelope Isolation actuation trains, or two manual trains. The Required Action is to isolate the normal ventilation to the MCR/ESGR envelope immediately. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation.

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 recently irradiated fuel assemblies are being moved. Either the normal ventilation to MCR/ESGR envelope must be isolated or movement of recently irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require MCR/ESGR Envelope Isolation actuation.

BASES

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 MCR/ESGR Envelope Isolation Actuation Functions.

SR 3.3.6.1

SR 3.3.6.1 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. Each Manual Actuation Function is tested up to, and including, the master relay coils. 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 TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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.

REFERENCES None

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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 RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are compared to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. RCS loop average temperature is compared to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the unit safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR criterion. The limits on the DNB related parameters assure that each of the parameters are maintained within the normal steady state envelope of

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BASES

APPLICABLE SAFETY ANALYSES (continued)	operation assumed in the transient and accident analysis. The limits have been analytically demonstrated to be adequate to maintain a minimum DNBR greater than the design limit throughout each analyzed transient including allowances for measurement uncertainties. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed for include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis 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 equal the analytical limits because of the application of statistical combination of uncertainty. The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
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, usually based on the maximum analyzed steam generator tube plugging, is retained in the LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient. The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location 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. The

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BASES

APPLICABILITY (continued)

design basis events that are sensitive to DNB in other MODES (MODE 2 through 5) have sufficient margin to DNB, and therefore, there is no reason to restrict DNB in these MODES.

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.

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 unit parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on unit operating experience.

BASES

ACTIONS (continued)

B.1

If Required Action A.1 is not met within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 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 unit conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.2

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.3

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 based on operating experience, equipment reliability, and plant risk and 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 30 days after ≥ 90% RTP. The 30 day period after reaching 90% RTP is reasonable to establish stable operating conditions, install the test equipment, perform the test, and analyze the results. The Surveillance shall be performed within 30 days after reaching 90% RTP.

REFERENCES

1. UFSAR, Chapter 15.

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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 unit 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

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal from subcritical, RCCA ejection, boron dilution at startup, feedwater malfunction, main steam system depressurization, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 547°F. 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 unit 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, "MODE 2 PHYSICS TESTS Exceptions," 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.

BASES

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 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 unit systems.

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

None.

Intentionally Blank

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.

This LCO 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.

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

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

(continued)

BASES

BACKGROUND (continued)

The actual shift in the RT_{NDT} of the vessel material is established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves are adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 5).

The P/T limit curves are calculated using the most limiting value of RT_{NDT} corresponding to the limiting beltline region material for the reactor vessel.

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

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. 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.

The reactor vessel beltline is the most limiting region of the reactor vessel for the determination of P/T limit curves. The P/T curves include a correction for the difference between the pressure at the point of measurement (hot leg or pressurizer) and the reactor vessel beltline. The P/T limits include instrument uncertainties for pressure and temperature.

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.

BASES

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. 1). 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.

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. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 unit 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.

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 unit to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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

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. 6), 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 limits is required when RCS pressure and temperature conditions are undergoing planned changes. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 unit 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. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

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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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the unit have been performed assuming three RCS loops are in operation. The majority of the unit safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the complete loss of forced reactor flow, single reactor coolant pump locked rotor, partial loss of forced reactor flow, and rod withdrawal events (Ref. 1).

The DNB analyses assume normal three loop operation. Uncertainties in key unit operating parameters, nuclear and thermal parameters, and fuel fabrication parameters are considered statistically such that there is at least a 95 percent probability that DNB will not occur for the limiting power rod. Key unit parameter uncertainties are used to determine the unit departure from nucleate boiling ratio (DNBR) uncertainty. This DNBR uncertainty, combined with the DNBR limit, establishes a design DNBR value which must be met in unit safety analyses and is used to determine the pressure and temperature Safety Limit (SL). Since the parameter uncertainties are considered in determining the design DNBR value, the unit safety analyses are performed using values of input parameters without uncertainties. Therefore, nominal operating values for reactor coolant flow are used in the accident analyses.

The unit is designed to operate with all RCS loops in operation to maintain DNBR above the limit during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

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 DNBR, 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.

BASES

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.

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";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "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 unit to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNBR 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 the DNBR limit. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES 1. UFSAR, Chapter 15.

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, two RCS loops are 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, 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.

Therefore, in MODE 3 with RTBs in the closed position and Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least one RCS loop to be OPERABLE and in operation to ensure that the accident analyses limits are met.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 and one of those loops be in operation. 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 redundant capability 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 permit pump swap operations and tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to 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 may be revalidated by conducting the test again. Another test that may be 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 pump swap or the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

(continued)

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 ensure 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 the 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.

Operation in other MODES is covered by:

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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

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

(continued)

BASES

ACTIONS

A.1 (continued)

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 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 unit conditions in an orderly manner and without challenging unit systems.

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

If two required RCS loops are inoperable or a required RCS loop is not in operation, except as during conditions permitted by the Note in the LCO section, place the Rod Control System 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). 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 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 removes the possibility of an inadvertent rod withdrawal. 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 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.

BASES

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 based on operating experience, equipment reliability, and plant risk and 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 ≥ 17% for required RCS loops. If the SG secondary side narrow range water level is < 17%, 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.3

Verification that the 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 the required RCP. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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.

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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 OPERABLE to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. 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

(continued)

BASES

LCO (continued)

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 ≤ 1 hour per 8 hour period. The purpose of the Note is to permit pump swap operations and tests that are designed to validate various accident analyses values. One of the tests which may be 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. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values may be revalidated by conducting the test again. The 1 hour time period is adequate to perform the pump swap or test, and operating experience has shown that boron stratification is not a problem 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 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 meet the SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure the 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 SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature

(continued)

BASES

LCO (continued)

≤ 280°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop is comprised of 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 is comprised of 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 provide redundancy for heat removal.

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";
LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

<u>A.1</u>

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 paths for heat removal.

BASES

ACTIONS (continued)

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 unit systems.

This Required Action is modified by a Note which indicates that the unit must be placed in MODE 5 only if an 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 an 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 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 decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

BASES

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 based on operating experience, equipment reliability, and plant risk and 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 ≥ 17%. If the SG secondary side narrow range water level is < 17%, 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.3

Verification that the 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 the required pump. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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.

Intentionally Blank

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, protection, 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 a SG with secondary side water level of at least 17% using narrow range instrumentation to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops—MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

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 a SG with secondary side water level ≥ 17% using narrow range instrumentation and the associated loop isolation valves open. 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 provide redundancy for heat removal. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is a SG with its secondary side water level ≥ 17% using narrow range instrumentation. Should the operating RHR loop fail, the SG could be used to remove the decay heat via natural circulation.

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 swap operations and tests designed to validate various accident analyses values. One of the tests 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 stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is adequate to perform the pump swap or test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

(continued)

BASES

LCO (continued)

Utilization of Note 1 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 meet the SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure the 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 on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature ≤ 280°F. 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 with circulation provided by an RCP.

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.

BASES

APPLICABILITY

In MODE 5 with the unisolated portion of the RCS loops 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 SG is required to be ≥ 17% with the associated loop isolation valves open.

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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

If all RCS loops are isolated, an SG cannot be used for decay heat removal and RCS water inventory is substantially reduced. In this circumstance, LCO 3.4.8 applies.

ACTIONS

A.1, A.2, B.1, and B.2

If one RHR loop is OPERABLE and the required SG has secondary side water level < 17%, 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 paths. 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 Note 1 and Note 4, or if no required RHR 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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.2

Verifying that at least one SG is OPERABLE by ensuring its secondary side narrow range water level is ≥ 17% 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.3

Verification that the 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 the required RHR pump. If secondary side water level is ≥ 17% in at least one SG, this Surveillance is not needed. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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.

BASES

REFERENCES

1. NRC Information Notice 95-35, Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation.

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, 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. 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, 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 paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. 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 provide redundancy for heat removal.

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

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BASES

LCO (continued)

temperature is maintained > 10°F below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained 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 that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible.

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 the unisolated portion of the loops not filled, 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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

If all RCS loops are isolated, the RCS water inventory is substantially reduced. In this circumstance, LCO 3.4.8 applies whether or not the isolated loops are filled.

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 paths for heat removal.

BASES

ACTIONS (continued)

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 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.2

Verification that the 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 the required pump. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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.

BASES

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. There are 5 groups of pressurizer heaters. Groups 1, 2, 4, and 5 are backup heaters. Group 3 consists of proportional heaters. Groups 1 and 4 are powered from the emergency busses and are governed by this Specification. 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

(continued)

BASES

BACKGROUND (continued)	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.
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 unless their operation would increase the severity of the event; however, an implicit initial condition assumption of the safety analyses is that the pressure control system is maintaining RCS pressure in the normal operating range. 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 ≤ 1240 cubic feet, which is equivalent to ≤ 93%, 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 groups of OPERABLE pressurizer heaters, each with a capacity ≥ 125 kW, capable of being powered from an emergency bus. The two heater groups are designated as

(continued)

BASES

LCO (continued)

Group 1 and Group 4. 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 exact design value of 125 kW is derived from the use of seven heaters rated at 17.9 kW each. The amount needed to maintain pressure is dependent on the heat losses.

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 bus. 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, the need for pressurizer heaters supplied from an emergency bus to maintain pressure control is reduced because core heat is reduced, and has a correspondingly lower effect on pressurizer level and RCS pressure control. In addition, other mechanisms, such as the Residual Heat Removal (RHR) System and the Power Operated Relief Valves (PORVs) are available to control RCS temperature and pressure should normal offsite power be lost.

ACTIONS

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

Pressurizer water level control malfunctions or other unit evolutions may result in a pressurizer water level above the nominal upper limit, even with the unit at steady state conditions. Normally the unit will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level—High Trip.

(continued)

ACTIONS

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

If the pressurizer water level is not within the limit, action must be taken to bring the unit 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

B.1

If one required group 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 may be maintained during this time using the remaining heaters.

C.1 and C.2

If one group of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 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 3.4.9.1

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS

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 their required rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.
2. NUREG-0737, November 1980.

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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 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 relief capacity for each valve, 380,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine, a locked reactor coolant pump rotor, and reactivity insertion due to control rod withdrawal. The complete loss of steam flow is typically the limiting event. The limiting event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. 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, increase in the pressurizer relief tank temperature or level, or by the acoustic monitors located on the relief line.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with one or more RCS cold leg temperatures ≤ 280°F, 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, "Low Temperature Overpressure Protection (LTOP) System."

The safety valve pressure tolerance limit is expressed as an average value. The as-found error, expressed as a positive or negative percentage of each tested safety valve, is summed and divided by the number of valves tested. This average as-found value is compared to the acceptable range of +2% to -3%. In addition, no single valve is allowed to be outside of ±3%. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires

(continued)

BASES

BACKGROUND (continued)

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 in accordance with ASME Code, Section III (Ref. 1). The consequence of exceeding the ASME Code pressure limit could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

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 from full 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;

f. Locked rotor; and

g. Uncontrolled rod withdrawal from subcritical.

Description of the analyses of the above transients are contained in Reference 2. Safety valve actuation is required in events a, c, f and g (above) to limit the pressure increase. 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).

BASES

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 valve pressure tolerance limit is expressed as an average value. The as-found error, expressed as a positive or negative percentage of each tested safety valve, is summed and divided by the number of valves tested. This average as-found value is compared to the acceptable range of +2% to -3%. In addition, no single valve is allowed to be outside of ±3%. 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.

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP enabling 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 temperatures are ≤ 280°F or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

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. This method of testing is not currently used at North Anna, but it is an accepted method. Only one valve at a time may 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 industry experience that hot testing can be performed in this timeframe.

BASES

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 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 hours and to MODE 4 with any RCS cold leg temperatures ≤ 280°F 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. With any RCS cold leg temperatures at or below 280°F, overpressure protection is provided by the LTOP System. 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. No additional requirements are specified.

The pressurizer safety valve lift setting given in the LCO is for OPERABILITY; however, the valves are reset to ±1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.

2. UFSAR, Chapter 15.

3. WCAP-7769, Rev. 1, June 1972.

BASES

REFERENCES (continued)	4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

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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 air or nitrogen operated valves that are controlled to open at a 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 unit 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.

The PORVs, their block valves, and their controls are powered from the emergency buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power. The PORVs are air operated valves and normally are provided motive force by the Instrument Air System. A backup, nitrogen supply for the PORVs is also available. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

The unit has two PORVs, each having a relief capacity of 210,000 lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer

(continued)

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 (LTOP). See LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."
APPLICABLE SAFETY ANALYSES	Unit operators employ the PORVs to depressurize the RCS in response to certain unit 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 two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. 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

(continued)

BASES

LCO (continued)

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.

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 to within LCO 3.4.13, "RCS Operational Leakage."

Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORVs and their associated block valves are required to be OPERABLE to limit the potential for a small break LOCA through the flow path and for manual operation to mitigate the effects associated with an SGTR. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate an SGTR event. 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.

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

Note 1 has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

BASES

ACTIONS (continued)

A.1

The PORVs are provided normal motive force by the Instrument Air system and have a backup nitrogen supply. If the backup nitrogen supply is inoperable, the PORVs are still capable of being manually cycled provided the Instrument Air system is available. The Instrument Air system is highly reliable and the likelihood of its being unavailable during a demand for PORV actuation is low enough to justify a 14 day Completion Time for return of the backup nitrogen supply to OPERABLE status.

B.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 unit 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 unit operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

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

If one PORV 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 Time of 1 hour is reasonable, based on challenges to the PORVs during this time period, and provides the operator adequate time to correct the situation. If the inoperable valve cannot be restored to being capable of being manually cycled (permitting entry into Condition B), or OPERABLE status, it must be isolated within the specified time. Because there is one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the unit must be brought to a MODE in which the LCO does not apply, as required by Condition E.

BASES

ACTIONS (continued)

D.1 and D.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. 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 at least one PORV remains 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 C, since the PORVs 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 unit must be brought to a MODE in which the LCO does not apply, as required by Condition E.

The Required Actions D.1 and D.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 another Required Action. 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 C 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).)

E.1 and E.2

If the Required Action of Condition A, B, C, or D is not met, then 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

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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. In MODE 4, automatic PORV OPERABILITY is required. See LCO 3.4.12.

F.1 and F.2

If more than one PORV is inoperable and not capable of being manually cycled, then 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. In MODE 4, automatic PORV OPERABILITY is required. See LCO 3.4.12.

G.1

If two block valves are inoperable, it is necessary to restore at least one block valve within 2 hours. The Completion Time is reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

The Required Action G.1 is modified by a Note stating that the Required Action does not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with another Required Action. In this event, the Required Action for inoperable PORV (which requires the block valve power to be removed once it is closed) is adequate to address the condition. While it may be desirable to also place the PORV in manual control, this may not be possible for all causes of Condition C entry with PORV inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

H.1 and H.2

If the Required Actions of Condition G are not met, then 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

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

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. In MODE 4, automatic PORV OPERABILITY is required. See LCO 3.4.12.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

SR 3.4.11.1 requires verification that the pressure in the PORV backup nitrogen system is sufficient to provide motive force for the PORVs to cope with a steam generator tube rupture coincident with loss of the containment Instrument Air system. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.11.2

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 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.

Note 2 modifies this SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the test to be performed in MODE 3 under operating temperature and pressure conditions, prior to entering MODE 1 or 2.

SR 3.4.11.3

SR 3.4.11.3 requires 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. This testing is performed in MODES 3 or 4 to prevent possible RCS pressure transients with the reactor critical.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.3 (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

The Note modifies this SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the test to be performed in MODE 3 under operating temperature and pressure conditions, prior to entering MODE 1 or 2.

SR 3.4.11.4

Operating the solenoid control valves and check valves on the accumulators ensures the PORV control system actuates properly when called upon. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Regulatory Guide 1.32, February 1977.
2. UFSAR, Section 15.4.
3. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the LTOP System design basis pressure and temperature (P/T) limit curve (i.e., 100% of the isothermal P/T limit curve determined to satisfy the requirements of 10 CFR 50, Appendix G, Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. This specification provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," provides the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (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 P/T limits.

This LCO provides RCS overpressure protection by limiting coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all but one low head safety injection (LHSI) pump and one charging pump incapable of injection into the RCS and isolating the accumulators when accumulator pressure is greater than the PORV lift setting. The pressure relief capacity requires either two redundant RCS PORVs or a depressurized RCS and an

(continued)

BASES

BACKGROUND (continued)

RCS vent of sufficient size. One RCS PORV or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

With limited coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If conditions require the use of more than one LHSI and charging pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The LTOP System for pressure relief consists of two PORVs with reduced lift settings, or a depressurized RCS and an RCS vent of sufficient size. Two RCS PORVs are required for redundancy. One RCS PORV has adequate relieving capability to keep from overpressurization for the required coolant input capability.

PORV Requirements

As designed for the LTOP System, each PORV is signaled to open if the RCS pressure exceeds a limit determined by the LTOP actuation logic. The LTOP actuation logic monitors both RCS temperature and RCS pressure and determines when a condition is not acceptable. The wide range RCS temperature indications are auctioneered to select the lowest temperature signal.

The lowest temperature signal is passed to a comparator circuit which determines the pressure limit for that temperature. The 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, the PORVs are signaled to open.

The PORV setpoints are staggered so only one valve opens to stop a low temperature overpressure transient. If the opening of the first valve does not prevent a further increase in pressure, a second valve will open at its higher pressure setpoint to stop the transient. Having the setpoints of both valves within the limits in the LCO ensures that the LTOP System design basis P/T limit curve will not be exceeded in any analyzed event.

(continued)

BASES

BACKGROUND

PORV Requirements (continued)

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.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS within the LTOP design basis P/T limit curve 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 LTOP mass or heat input transient, and maintaining pressure below the LTOP System design basis P/T limit curve. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it requires either removing a pressurizer safety valve, or blocking open a PORV and opening its block valve, or similarly establishing a vent by opening an RCS vent valve. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 3) demonstrate that the reactor vessel is adequately protected against exceeding the LTOP System design basis P/T limit curve (i.e., 100% of the isothermal P/T limit curve determined to satisfy the requirements of 10 CFR 50, Appendix G, Ref. 1). In MODES 1, 2, and 3, and in MODE 4 with RCS cold leg temperature exceeding 280°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At 280°F and below, overpressure prevention falls to two OPERABLE RCS PORVs or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

The RCS cold leg temperature below which LTOP protection must be provided increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the P/T curves are revised, the LTOP System must be

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

re-evaluated to ensure its functional requirements can still be met using the PORV method or the depressurized and vented RCS condition.

The LCO contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 3 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

<u>Heat Input Type Transients</u>

a. Reactor coolant pump (RCP) startup with temperature asymmetry between the RCS and steam generators.

The following are required during the LTOP MODES to ensure that mass and heat input transients do not occur, which either of the LTOP overpressure protection means cannot handle:

a. Rendering all but one LHSI pump and one charging pump incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions when accumulator pressure is greater than the PORV lift setting; and

c. Disallowing start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop. LCO 3.4.6, "RCS Loops—MODE 4," and LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," provide this protection.

The Reference 3 analyses demonstrate that either one PORV or the depressurized RCS and RCS vent can maintain RCS pressure below limits when only one LHSI pump and one charging pump are actuated. Thus, the LCO allows only one LHSI pump and one charging pump OPERABLE during the LTOP MODES. The

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Heat Input Type Transients (continued)

Reference 3 analyses do not explicitly model actuation of the LHSI pump, since the RCS pressurization resulting from inadvertent safety injection by a single charging pump against a water-solid RCS would not be made more severe by such actuation. Since the LTOP analyses assume that the accumulators do not cause a mass addition transient, when RCS temperature is low, the LCO also requires the accumulators to be isolated when accumulator pressure is greater than the PORV lift setting. The isolated accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

Fracture mechanics analyses established the temperature of LTOP Applicability at 280°F.

The consequences of a small break loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 (Ref. 4), requirements by having a maximum of one LHSI pump and one charging pump OPERABLE.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the allowable values shown in the LCO. The setpoint allowable values are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP transient of one charging pump injecting into the RCS. These analyses consider pressure overshoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived value ensure the RCS pressure at the reactor vessel beltline will not exceed the LTOP design P/T limit curve.

The PORV setpoint allowable values are evaluated when the P/T limits are modified. 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 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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 2.07 square inches is capable of mitigating the allowed LTOP overpressure transient. (A vent size of 2.07 square inches is the equivalent relief capacity of one PORV.) The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, one LHSI pump and one charging pump OPERABLE, maintaining RCS pressure less than the LTOP design basis P/T limit curve.

The RCS vent size is re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

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

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the LTOP System design basis P/T limit curve (i.e., 100% of the isothermal P/T limit curve determined to satisfy the requirements of 10 CFR 50, Appendix G, Ref. 1) as a result of an operational transient.

To limit the coolant input capability, the LCO requires a maximum of one LHSI pump and one charging pump capable of injecting into the RCS and all accumulator discharge isolation valves closed with power removed from the isolation valve operator, when accumulator pressure is greater than the PORV lift setting.

The LCO is modified by two Notes. Note 1 allows two charging pumps to be made capable of injection 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.

(continued)

BASES

LCO (continued)

Note 2 states that accumulator isolation is only required when the accumulator pressure is more than the PORV lift setting. This Note permits the accumulator discharge isolation valves to be open if the accumulator cannot challenge the LTOP limits.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs; or

   A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limits provided in the LCO and testing proves its ability to open at this setpoint, and backup nitrogen motive power is available to the PORVs and their control circuits.

b. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when open with an area of ≥ 2.07 square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ 280°F, 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 280°F. 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 280°F.

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.1 and B.1

With more than one LHSI pump and one charging pump 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.

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

An unisolated accumulator requires isolation immediately. Power available to an accumulator isolation valve operator must be removed in one hour. These ACTIONS are modified by a Note which states the Condition only applies if the accumulator pressure is more than the PORV lift setting.

If isolation is needed and cannot be accomplished, Required Action D.1 and Required Action D.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to > 280°F, the LCO is no longer Applicable. Depressurizing the accumulators below the PORV lift setting also exits the Condition.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering judgement indicating that an event requiring LTOP is not likely in the allowed times.

E.1

In MODE 4 when any RCS cold leg temperature is ≤ 280°F, with one RCS PORV inoperable, the RCS PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two 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 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)

F.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 5). 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 valves to OPERABLE status is 24 hours.

The Completion Time represents a reasonable time to investigate and repair PORV failures without exposure to a lengthy period with only one OPERABLE RCS PORV to protect against overpressure events.

G.1

The RCS must be depressurized and a vent must be established within 12 hours when:

a. Both required RCS PORVs are inoperable; or

b. A Required Action and associated Completion Time of Condition A, B, D, E, or F is not met; or

c. The LTOP System is inoperable for any reason other than Condition A, B, C, D, E, or F.

The vent must be sized ≥ 2.07 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the unit 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, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, a maximum of one LHSI pump and a maximum of one charging pump are verified

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3 (continued)

incapable of injecting into the RCS and the accumulator discharge isolation valves are verified closed with power removed from the isolation valve operator.

SR 3.4.12.3 is modified by a Note stating that the verification is only required when accumulator pressure is greater than the PORV lift setting. With accumulator pressure less than the PORV lift setting, the accumulator cannot challenge the LTOP limits and the isolation valves are allowed to be open.

The LHSI pumps and charging pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pull to lock and at least one valve in the discharge flow path being closed.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.4

The RCS vent of ≥ 2.07 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked.

b. The Surveillance Frequency for locked valves is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12b.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.5

The PORV block valve must be verified open every 72 hours 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. In addition, the PORV keyswitch must be verified to be in the proper position to provide the appropriated trip setpoints to the PORV actuation logic. This Surveillance is performed if the PORV is used to satisfy 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.6

SR 3.4.12.6 requires verification that the pressure in the PORV backup nitrogen system is sufficient to provide motive force for the PORVs to cope with an overpressure event. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.7

Performance of a COT is required on each required PORV to verify the PORV is capable of performing its LTOP function and, as necessary, adjust its lift setpoint. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The COT will verify the setpoint is within the allowed maximum limits in this specification. PORV actuation could depressurize the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.7 (continued)

RCS and is not required. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 entering a condition in which the PORV is required to be OPERABLE. The Note allows entering the LTOP Applicability prior to performing the SR. The 12-hour frequency considers the unlikelihood of a low temperature overpressure event during this time.

SR 3.4.12.8

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix G.

2. Generic Letter 88-11.

3. UFSAR, Section 5.2.2.2.

4. 10 CFR 50, Section 50.46.

5. 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.

General Design Criteria 3 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

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. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is one gallon per minute or increases to one gallon per minute as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a main steam line break (MSLB) accident. Other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The UFSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via power operated relief valves or safety valves. The source term in the primary system coolant is transported to the affected (ruptured) steam generator by the break flow. The affected steam generator discharges steam to the environment for 30 minutes until the generator is manually isolated. The 1 gpm primary to secondary LEAKAGE transports the source term to the unaffected steam generators. Releases continue through the unaffected steam generators until the Residual Heat Removal System is placed in service.

The MSLB is less limiting for site radiation releases than the SGTR. The safety analysis for the MSLB accident assumes 1 gpm primary to secondary LEAKAGE as an initial condition. The dose consequences resulting from the MSLB and SGTR accidents are within the limits defined in the staff approved licensing basis.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

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.

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.

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

(continued)

BASES

LCO

d. Primary to Secondary LEAKAGE through Any One SG (continued)

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 LEAKAGE, 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 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 unit conditions from full power conditions in an orderly manner and without challenging unit 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). 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.

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.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

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."

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.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 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 based on operating experience, equipment reliability, and plant risk and 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).

BASES

REFERENCES

1. UFSAR, Section 3.1.26.

2. Regulatory Guide 1.45, May 1973.

3. UFSAR, Chapter 15.

4. NEI 97-06, "Steam Generator Program Guidelines."

5. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

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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 General Design Criteria 55 (Refs. 1, 2, and 3), 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. The 1975 Reactor Safety Study, WASH-1400, (Ref. 4) identified intersystem LOCAs as a significant contributor to the risk of core melt. The study considered designs containing two in-series check valves and two check valves in series with an MOV which isolate the high pressure RCS from the low pressure safety injection system. The scenario considered is a failure of the two check valves leading to overpressurization and rupture of the low pressure injection piping which results in a LOCA that bypasses containment. A letter was issued (Ref. 5) by the NRC requiring plants to describe the PIV configuration of the plant. On April 20, 1981, the NRC issued an Order modifying the North Anna Unit 1 Technical Specifications to include testing requirements on PIVs and to specify the PIVs to be tested. The original North Anna 2 Technical Specifications, dated August 21, 1980, included a list of PIVs required to be tested and described the required testing. The valves required to be leak tested by this Specification are listed in Tables B 3.4.14-1 (Unit 1) and B 3.4.14-2 (Unit 2).

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 to which the LCO applies. 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

(continued)

BASES

BACKGROUND (continued)	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. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.
APPLICABLE SAFETY ANALYSES	Reference 4 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 ECCS low pressure 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 ECCS low pressure 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. RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The RCS PIVs required to be leak tested are listed in Tables B 3.4.14-1 (Unit 1) and B 3.4.14-2 (Unit 2). 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.

(continued)

BASES

LCO (continued)

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

Reference 6 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.

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, any valves in the RHR flow path that are required to be tested 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.

BASES

ACTIONS (continued)

A.1

Required Action A.1 requires that RCS PIV leakage be restored to within limit within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

B.1 and B.2

If leakage cannot be reduced 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 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on the affected 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. Leakage may be measured indirectly (as from the performance of pressure indicators) to satisfy ALARA requirements if supported by calculations verifying that the method is capable of demonstrating valve compliance with the leakage criteria.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

The Frequency is within frequency allowed by the American Society of Mechanical Engineers (ASME) Code (Ref. 6).

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

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 with stable conditions not possible in the MODES with lower pressures. If testing cannot be performed at these pressures, testing can be performed at lower pressures and scaled to operating pressure.

Entry into MODES 3 and 4 is allowed if needed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into 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. In addition, this Surveillance is not required to be performed on any RCS PIVs in the RHR System flow path 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 that are required to be tested must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

REFERENCES

1. 10 CFR 50.2.

2. 10 CFR 50.55a(c).

3. UFSAR, Section 3.1.48.1.

BASES

REFERENCES (continued)

4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.

5. Letter from D. G. Eisenhut, NRC, to all LWR licensees, LWR Primary Coolant System Pressure Isolation Valves, February 23, 1980.

6. ASME Code for Operation and Maintenance of Nuclear Power Plants.

7. 10 CFR 50.55a(g).

Table B 3.4.14-1 (page 1 of 1)
Unit 1 RCS PIVS Required To Be Tested

VALVE	FUNCTION
1-SI-83	Low Head Safety Injection to Cold Legs—Loop 1
1-SI-195	Low Head Safety Injection to Cold Legs—Loop 1
1-SI-86	Low Head Safety Injection to Cold Legs—Loop 2
1-SI-197	Low Head Safety Injection to Cold Legs—Loop 2
1-SI-89	Low Head Safety Injection to Cold Legs—Loop 3
1-SI-199	Low Head Safety Injection to Cold Legs—Loop 3

Table B 3.4.14-2 (page 1 of 1)
Unit 2 RCS PIVS Required To Be Tested

Valve	Function
2-SI-85	High head safety injection to cold legs and hot legs
2-SI-93	High head safety injection to cold legs and hot legs
2-SI-107	High head safety injection to cold legs and hot legs
2-SI-119	High head safety injection to cold legs and hot legs
MOV-2836	High head safety injection off charging header
MOV-2869A, B	High head safety injection off charging header
MOV-2867C, D	Boron injection tank outlet valves
2-SI-91	Low head safety injection to cold legs
2-SI-99	Low head safety injection to cold legs
2-SI-105	Low head safety injection to cold legs
2-SI-126	Low head safety injection to hot legs
2-SI-128	Low head safety injection to hot legs
2-SI-151	Accumulator discharge check valves
2-SI-153	Accumulator discharge check valves
2-SI-168	Accumulator discharge check valves
2-SI-170	Accumulator discharge check valves
2-SI-185	Accumulator discharge check valves
2-SI-187	Accumulator discharge check valves
MOV-2700	RHR system isolation valves
MOV-2701	RHR system isolation valves
MOV-2720A, B	RHR system isolation valves
MOV-2890A, B, C, & D	Low head safety injection to cold legs and hot legs

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

UFSAR, Chapter 3 (Ref. 1) requires compliance with Regulatory Guide 1.45, Revision 0 (Ref. 2). Regulatory Guide 1.45, Revision 0 describes acceptable methods for selecting RCS 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 in the control room 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. These leakage detection methods or systems differ in sensitivity and response time.

The containment sump used to collect unidentified LEAKAGE includes two sump level monitors that provide level indication. The "A" train level indicator provides input to a calculated discharge flow rate determined by the plant computer. Either level indication or the calculated containment sump discharge flow rate is acceptable for detecting increases in unidentified LEAKAGE.

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. One Containment Air Recirculation Fan (CARF) provides enough air flow for the operation of the radiation detectors.

(continued)

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 unit 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 are 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.

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. Multiple instrument locations are utilized, if needed, to ensure that the transport delay time of the leakage from its source to an instrument location yields an acceptable overall response time.

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 unit in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO requires two instruments to be OPERABLE.

The containment sump used to collect unidentified LEAKAGE includes two sump level monitors that provide level indication. The "A" train level indicator provides input to a calculated discharge flow rate determined by the plant

(continued)

BASES

LCO (continued)

computer. Either level indication or the calculated containment sump discharge flow rate is acceptable for detecting increases in unidentified LEAKAGE. 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 0.5 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 0.5 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.

BASES

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

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 flow). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit 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.

(continued)

BASES

ACTIONS

B.1.1, B.1.2, and B.2 (continued)

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.

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 flow). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit 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 only OPERABLE monitor is the containment atmosphere gaseous radiation monitor. The containment atmosphere gaseous radioactivity monitor typically cannot detect a 0.5 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 taken 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 capability. The 7 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If a Required Action of Condition A or B cannot be met, 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 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 unit systems.

E.1

With all required monitors inoperable, no required automatic means of monitoring leakage are available, and immediate unit shutdown in accordance with LCO 3.0.3 is required.

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 based on operating experience, equipment reliability, and plant risk and 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. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Chapter 3.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," dated May, 1973.
3. UFSAR, Chapter 5.2.4

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND	The maximum dose that an individual at the exclusion area boundary can receive for 2 hours following an accident, or at the low population zone outer boundary for the radiological release duration, is specified in 10 CFR 50.67 (Ref. 1). Doses to control room operators must be limited per GDC 19. The limits on specific activity ensure that the offsite and control room doses are appropriately limited during analyzed transients and accidents. The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the 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 DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and control room doses meet the appropriate acceptance criteria in the Standard Review Plan (Ref. 2).
APPLICABLE SAFETY ANALYSES	The LCO limits on the specific activity of the reactor coolant ensure that the resulting offsite and control room doses meet the appropriate SRP acceptance criteria following a SLB or SGTR accident. The safety analyses (Refs. 3 and 4) assume the specific activity of the reactor coolant is at the LCO limits, and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm exists. The safety analyses assume the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.18, "Secondary Specific Activity." The analyses for the SLB and SGTR accidents establish the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety analyses consider two cases of reactor coolant iodine specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a SLB (by a factor of 500), or SGTR (by a factor of 335), respectively. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to an iodine spike caused by a reactor or an RCS transient prior to the accident. In both cases, the noble gas specific activity is assumed to be 197 μCi/gm DOSE EQUIVALENT XE-133.

The SGTR analysis also assumes a loss of offsite power at the same time as the reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the Residual Heat Removal (RHR) system is placed in service.

The SLB radiological analysis assumes that offsite power is lost at the same time as the pipe break occurs outside containment. Reactor trip occurs after the generation of an SI signal on low steam line pressure. The affected SG blows down completely and steam is vented directly to the atmosphere. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the RHR system is placed in service.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed 60.0 μCi/gm for more than 48 hours.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The iodine specific activity in the reactor coolant is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 197 μCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that offsite and control room doses will meet the appropriate SRP acceptance criteria (Ref. 2).

The SLB and SGTR accident analyses (Refs. 3 and 4) show that the calculated doses are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of a SLB or SGTR, lead to doses that exceed the SRP acceptance criteria (Ref. 2).

APPLICABILITY

In MODES 1, 2, 3, and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of a SLB or SGTR to within the SRP acceptance criteria (Ref. 2).

In MODES 5 and 6, the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, the monitoring of RCS specific activity is not required.

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 specific activity is ≤ 60.0 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is continued every 4 hours to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limit within 48 hours. The Completion Time of 48 hours is acceptable since it is expected that, if there were an iodine spike, the normal coolant iodine concentration would be restored within this time period. Also, there is a low probability of a SLB or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Actions A.1 and A.2 while the DOSE EQUIVALENT I-131 LCO limit is not met. This allowance is acceptable due

(continued)

BASES

ACTIONS (continued)

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.

B.1

With the DOSE EQUIVALENT XE-133 greater than the LCO limit, DOSE EQUIVALENT XE-133 must be restored to within limit within 48 hours. The allowed Completion Time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period. Also, there is a low probability of a SLB or SGTR occurring during this time period.

A Note permits that the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Action B.1 while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to 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.

C.1 and C.2

If the Required Action and associated Completion Time of Condition A or B is not met, or if the DOSE EQUIVALENT I-131 is > 60.0 μCi/gm, 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 required plant conditions 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 noble gas specific activity of the reactor coolant. 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 the noble gas specific activity.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.1 (continued)

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

Due to the inherent difficulty in detecting Kr-85 in a reactor coolant sample due to masking from radioisotopes within similar decay energies, such as F-18 and I-134, it is acceptable to include the minimum detectable activity for Kr-85 in the SR 3.4.16.1 calculation. If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 is not detected, it should be assumed to be present at the minimum detectable activity.

SR 3.4.16.2

This Surveillance is performed to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The Frequency, between 2 and 6 hours after a power change $\geq$ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following the iodine spike initiation; samples at other times would provide inaccurate results.

BASES

REFERENCES

1. 10 CFR 50.67.
2. Standard Review Plan (SRP) Section 15.0.1 "Radiological Consequence Analyses Using Alternative Source Terms."
3. UFSAR, Section 15.4.2.
4. UFSAR, Section 15.4.3.

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 are used to perform maintenance 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 and equipment interlocks 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 are used for performing maintenance in MODES 5 and 6.

(continued)

BASES

LCO (continued)

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."

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 interlocks prevent the valve from being operated. Although operating procedures and interlocks 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 unit 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

(continued)

BASES

ACTIONS	B.1, B.2, and B.3 (continued) resulting in positive reactivity insertion. The Completion Time of Required Action B.1 allows time for borating the operating loops to a shutdown boration level such that the unit 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.
SURVEILLANCE REQUIREMENTS	SR 3.4.17.1 The Surveillance is performed to ensure that the RCS loop isolation valves are open prior to removing power from the isolation valve operator. There is no remote position indication available after power is removed from the valve operators. The valves will maintain their last position when power is removed for the valve operator. SR 3.4.17.2 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 15.2.6.

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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 maintenance. While operating with a loop isolated, there is potential for inadvertently opening the isolation valves in the isolated loop. In this event, any coolant in the isolated loop would 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 temperature in the isolated loop is lower than the temperature in the operating Residual Heat Removal (RHR) or RCS loops (cold water incident); or

b. The boron concentration in the isolated loop is lower than the boron concentration required to meet the SDM of LCO 3.1.1 or the boron concentration of LCO 3.9.1 (boron dilution incident).

If the loop is drained of coolant, startup of an isolated loop will cause coolant to flow from the RCS into the isolated portion of the loop with the potential to lower the RCS water level and cause a loss of suction to the RHR System pumps.

As discussed in the UFSAR (Ref. 1), the startup of a filled, isolated loop is done in a controlled manner that virtually eliminates any sudden reactivity addition from cold water or boron dilution because:

a. This LCO and unit operating procedures require that the boron concentration in the isolated loop be equal to or greater than the boron concentration required to meet the SDM of LCO 3.1.1 or the boron concentration of LCO 3.9.1 prior to opening the isolation valves, thus eliminating the potential for introducing coolant from the isolated loop that could dilute the boron concentration in the operating loops below the required limit.

b. The cold leg loop isolation valve cannot be opened unless the loop has been operated with the hot leg isolation valve open and recirculation flow of ≥ 125 gpm for

(continued)

BASES

BACKGROUND

b. (continued)

$\geq$ 90 minutes. This ensures that the temperatures of both the hot leg and cold leg of the isolated loop are within 20°F of the operating loops and 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 the boron concentration of LCO 3.9.1. Compliance with the recirculation requirement is ensured by operating procedures and automatic interlocks.

c. Other automatic interlocks prevent opening the hot leg loop isolation valve unless the cold leg loop isolation valve is fully closed.

The startup of an initially drained, isolated loop is performed in a controlled manner to ensure that sufficient water is available in the RCS to support RHR operation. In this case, the automatic interlocks are defeated and the isolated loop is filled under administrative control.

APPLICABLE SAFETY ANALYSES

During startup of a filled isolated loop, the cold leg loop isolation valve interlocks and operating procedures prevent opening the valve until the isolated loop and active RCS volume temperatures are equalized and the boron concentration is within limit. This ensures that any undesirable reactivity effect from the isolated loop does not occur.

An evaluation of the effects of opening the loop isolation valves with the boron concentration or temperature requirements of the filled, isolated portion not met is described in Reference 1. Failure to follow the requirements in the LCO could result in the RCS boron concentration or coolant temperature being reduced with a corresponding reduction in SDM. The evaluation concluded that adequate time is available for an operator to identify and respond to such an event prior to reactor criticality.

The initial RCS volume requirements ensure that the operation of the RHR System is not impaired during the filling of an isolated loop from the RCS should the isolation valves on three drained, isolated loops be inadvertently opened.

RCS isolated loop startup satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Loop isolation valves are used for performing maintenance when the unit is in MODE 5 or 6. This LCO governs the return to operation of an isolated loop (i.e., the hot and cold leg loop isolation valves are initially closed) and ensures that the loop isolation valves remain closed unless acceptable conditions for opening the valves are established.

There are two methods for returning an isolated loop to operation. The first method is used when the isolated loop is filled with water. When using the filled loop method, the hot leg isolation valve (e.g., the inlet valve to the isolated portion of the loop) is opened first. As described in LCO 3.4.18.a, the water in the isolated loop must be borated to at least the boron concentration needed to provide the required shutdown margin prior to opening the hot leg isolation valve. This ensures that the RCS boron concentration is not reduced below that required to maintain the required shutdown margin. The water in the isolated loop is then mixed with the water in the RCS by establishing flow through the recirculation line (which bypasses the cold leg isolation valve). After the flow through the recirculation line has thoroughly mixed the water in the isolated loop with the water in the RCS and it is verified that the isolated loop temperature is no more than 20°F below the temperature of the RCS (to avoid reactivity additions due to reduced RCS temperature), the cold leg isolation valve may be opened.

The second method for returning an isolated loop to operation is described in LCO 3.4.18.b and is used when the isolated loop is drained of water. In the drained loop method, the water in the RCS is used to fill the isolated portion of the loop. The LCO also requires that the pressurizer water level be established sufficiently high prior to and during the opening of the isolation valves to ensure that the inadvertent opening of all three sets of loop isolation valves on three drained and isolated loops would not result in loss of net positive suction head for the Residual Heat Removal system.

The LCO is modified by a Note which allows Reactor Coolant Pump (RCP) seal injection to be initiated to a RCP in a drained, isolated loop. This is to support vacuum assisted backfill of the loop. In this method, a vacuum is drawn on the isolated loop prior to opening the cold leg isolation valve in order to minimize the amount of trapped air in the loop and to minimize the need to run the RCP in the isolated loop to clear out air pockets. In order to draw a vacuum on

(continued)

BASES

LCO (continued)

the isolated loop, the RCP seals must be filled with water. The boron concentration of the water used for seal injection must meet the same requirements as the reactor coolant system and the loop must be drained prior to starting seal injection in order to be sure that no water at a boron concentration less than required remains in the isolated loop.

The LCO is modified by a Note which allows a hot or cold leg isolation valve to be closed for up to two hours without considering the loop isolated and meeting the LCO requirements when opening the closed valve. This allows for necessary maintenance and testing on the valves and the valve operators. If the closed valve is not reopened with two hours, it is necessary to close both isolation valves on the affected loop and follow the requirements of the LCO when reopening the isolation valves. This is required because there is a possibility that the water in the isolated loop has become diluted or cooled to the point that reintroduction of the water into to the reactor vessel could result in a significant reactivity change.

APPLICABILITY

In MODES 5 and 6, RCS loops may be isolated to perform maintenance. When a filled, isolated loop is to be put in operation, the isolated loop boron concentration and temperature must be controlled prior to opening the loop isolation valves in order to avoid the potential for positive reactivity addition. When an initially drained, isolated loop is to be put into operation, sufficient RCS inventory must be available to ensure that RCS water level continues to support RHR operation. The LCO water level requirement is sufficient to ensure that RCS water level does not drop below that required for RHR operation. In MODES 1, 2, 3 and 4, the loop isolation valves are required to be open with power to the valve operators removed by LCO 3.4.17, "RCS Loop Isolation Valves."

ACTIONS

A.1, B.1, and C.1

Required Actions A.1, B.1, and C.1 apply when the requirements of LCO 3.4.18.a are not met and a loop isolation valve has been opened. Therefore, the Actions require immediate closure of isolation valves to preclude a boron dilution event or a cold water event or RCS water level falling below that required for RHR operation.

BASES

ACTIONS (continued)

D.1, D.2, E.1 and E.2

Required Actions D.1, D.2, E.1 and E.2 apply when the requirements of LCO 3.4.18.b are not met and an initially drained, isolated loop is filled from the active RCS volume by opening a loop isolation valve. If the RCS water level requirement is not met, there is the possibility of insufficient net positive suction head to support the RHR pumps. If the RCP seal injection boron concentration requirements are not met, there is the possibility of diluting the reactor coolant boron concentration below that which is required. In both cases, the isolation valve(s) are to be closed and the requirements of the LCO must be met prior to opening the isolation valves. If both isolation valves on the loop are not fully opened within 2 hours, the lack of flow through the closed valve(s) could result in the boron concentration of the previously isolated portion of the loop being significantly different from the remainder of the RCS. The boron concentration in the isolated loop must be verified to be within limit or the isolation valve(s) are to be closed and the requirements of the LCO must be met prior to opening the isolation valves.

F.1

If power is restored to one or more closed loop isolation valve operators without the initial conditions in LCO 3.4.18.a.1 or LCO 3.4.18.b.1 being met, the potential exists for accidental startup of an isolated loop and possible reduction in shutdown margin. 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 interlocks prevent the valve from being operated. Although operating procedures and interlocks 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1

This Surveillance is performed to ensure that the temperature differential between a filled, isolated loop and the operating loops is ≤ 20°F. The loop stop valve interlocks

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1 (continued)

ensure that the temperature of the isolated loop is equalized with the temperature of the operating loops by requiring that the isolated loop is operated for at least 90 minutes with a recirculation flow of ≥ 125 gpm. The safety analysis neglects the uncertainty associated with measuring recirculation flow due to the insignificant effect on the analysis. Performing the Surveillance 30 minutes prior to opening the cold leg isolation valve in the isolated loop provides reasonable assurance, based on engineering judgment, that the temperature differential will stay within limits until the cold leg isolation valve is opened. This Frequency has been shown to be acceptable through operating experience.

The Surveillance is modified by a Note which states that the Surveillance is only required to be met when utilizing the requirements of the LCO applicable to starting a filled, isolated loop.

SR 3.4.18.2

To ensure that the boron concentration of a filled, isolated loop is greater than or equal to the boron concentration required to meet the SDM of LCO 3.1.1 or the boron concentration of LCO 3.9.1, a Surveillance is performed 1 hour prior to opening either the hot or cold leg isolation valve. Performing the Surveillance 1 hour prior to opening either the hot or cold leg isolation valve provides reasonable assurance the boron concentration difference will stay within acceptable limits until the loop is unisolated. This Frequency is a reasonable amount of time given that the isolated loop boron concentration changes slowly and the time required to request and have analyzed a boron concentration measurement prior to opening the isolation valve.

The Surveillance is modified by a Note which states that the Surveillance is only required to be met when utilizing the requirements of the LCO applicable to starting a filled, isolated loop.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.18.3

This Surveillance is performed to ensure that a filled, isolated loop is recirculated, with the hot leg isolation valve open, for at least 90 minutes at a flow rate of at least 125 gpm. This will ensure that the boron concentration and temperature of the isolated loop is similar to those of the operating loops. The Frequency of within 30 minutes prior to opening the cold leg isolation valve in a filled, isolated loop is considered a reasonable time to prepare for the opening of the cold leg isolation valve. The Surveillance is modified by a Note which states that the Surveillance is only required to be met when utilizing the requirements of the LCO applicable to starting a filled, isolated loop.

SR 3.4.18.4

This Surveillance is performed to ensure that an isolated loop is drained before opening an isolation valve to fill the isolated portion of the RCS from the RCS active volume or before initiating seal injection to the RCP in the isolated loop. This verification is performed to prevent unsampled water in a partially filled, isolated loop from mixing with the water in the RCS and potentially causing reactivity changes due to differences in boron concentration. The Frequency of within 2 hours prior to filling an initially drained loop from the active RCS volume or within 2 hours of initiating seal injection to the RCP in the isolated loop is considered a reasonable time to prepare for the opening of the isolation valve. The Surveillance is modified by a Note which states that the Surveillance is only required to be met when utilizing the requirements of the LCO applicable to starting an initially drained, isolated loop.

SR 3.4.18.5

This Surveillance verifies that the boron concentration of the water used for seal injection to the RCP in the isolated loop is borated to the same requirement as the RCS. This will prevent the water used for seal injection from diluting the water in the RCS. The LCO is modified by two Notes. Note 1 states that the Surveillance is only required to be met when utilizing the requirements of the LCO applicable to starting an initially drained, isolated loop. Note 2 states that the Surveillance is only required to be met when using blended flow as the source for RCP seal injection. The other sources

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.18.5 (continued)

for seal injection are required to be borated to at least the required boron concentration and are periodically verified by other specifications. The Frequency of within 1 hour prior to initiating seal injection flow and once per hour during filling of an initially drained loop from the active RCS volume is considered a reasonable time to monitor the seal injection boron concentration.

SR 3.4.18.6

This Surveillance verifies that there is sufficient water in the RCS when filling an initially drained, isolated portion of the RCS. The volume of water required is sufficient to continue to support RHR operation in the event of the inadvertent opening of the isolation valves on three isolated and drained loops. The required level of 32% incorporates inaccuracies due to use of instruments calibrated at cold conditions. If instruments calibrated at hot conditions are used, an indicated level of 39% is required due to the increased instrument uncertainty. The Frequency of every 15 minutes during filling of a drained, isolated loop ensures that the operators are aware of the water level during the filling operation. The Surveillance is modified by a Note which states that the Surveillance is only required to be met when utilizing the requirements of the LCO applicable to starting a drained, isolated loop.

SR 3.4.18.7

This Surveillance is performed to ensure that the boron concentration of an isolated loop satisfies the boron concentration requirements of the RCS prior to completely opening the cold leg isolation valve or opening the hot leg isolation valve. The Surveillance is modified by a Note which states that the Surveillance is only required to be met when utilizing the requirements of the LCO applicable to starting an initially drained, isolated loop. The Frequency of within 1 hour prior to fully opening the cold leg isolation valve or opening the hot leg isolation valve is considered a reasonable time to prepare for the opening of the isolation valves.

REFERENCES

1. UFSAR, Section 15.2.6.

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 forced 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 General Design Criteria 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 unit 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 is performed prior to initial criticality, during startup, and following low power operations.

The tests will include verifying the ability to establish and maintain natural circulation following a unit trip, performing natural circulation cooldown on emergency power, and during the cooldown, showing that adequate boron mixing 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 unit 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 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, unit 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 ≤ 25% RTP. This ensures, if some problem caused the unit to enter MODE 1 and start increasing unit 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 unit'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.

BASES

ACTIONS

A.1

When THERMAL POWER is ≥ the P-7 interlock setpoint 10%, 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.19.1

Verification that the power level is < the P-7 interlock setpoint (10%) will ensure that the fuel design criteria are not violated during the performance of the PHYSICS TESTS. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.19.2

The power range and intermediate range neutron detectors, P-10, and P-13 interlock setpoint 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 Impulse Chamber 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. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS. The SR 3.3.1.8 Frequency is sufficient for the power range and intermediate range neutron detectors to ensure that the instrumentation is OPERABLE before initiating PHYSICS TESTS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 Impulse Chamber 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. This will ensure that the RTS is properly functioning to provide the required degree of core protection during the performance of the PHYSICS TESTS.

REFERENCES

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

2. UFSAR, Section 3.1.1.

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. SG 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.

SG tubing is subject to a variety of degradation mechanisms. SG 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 5.5.8, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.8, 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 5.5.8. Meeting the

(continued)

BASES

BACKGROUND (continued)

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).

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting basis event for SG tubes and avoiding a SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate of 1 gpm, which is conservative with respect 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 UFSAR analysis for SGTR assumes the contaminated secondary fluid is released via power operated relief valves or safety valves. The source term in the primary system coolant is transported to the affected (ruptured) steam generator by the break flow. The affected steam generator discharges steam to the environment for 30 minutes until the generator is manually isolated. The 1 gpm primary to secondary LEAKAGE transports the source term to the unaffected steam generators. Releases continue through the unaffected steam generators until the Residual Heat Removal System is placed in service.

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 based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute or is assumed to increase to 1 gallon per minute as a result of accident induced conditions. 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. 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 GDC 19 (Ref. 2), 10 CFR 50.67 (Ref. 3) or RG 1.183 (Ref. 4), as appropriate.

SG tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged 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 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 5.5.8, "Steam 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

(continued)

BASES

LCO (continued)

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. 5) and Draft Regulatory Guide 1.121 (Ref. 6).

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. The accident analysis assumes that accident induced leakage does not exceed 1 gpm. 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.

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

SG 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.

(continued)

BASES

APPLICABILITY (continued)

SG integrity limits are not provided in MODES 5 and 6 since RCS conditions are far less challenging than 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 separate Conditions entry is permitted 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

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged 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 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 that should have been plugged 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged 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.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging 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 also specifies the inspection methods to be used to find potential degradation. Inspection methods are a

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.20.1 (continued)

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. 7). 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 5.5.8 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 5.5.8 until subsequent inspections support extending the inspection interval.

SR 3.4.20.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 5.5.8 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 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.

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 criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

BASES

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 50.67.
4. RG 1.183, July 2000.
5. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
6. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
7. 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 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

(continued)

BASES

BACKGROUND (continued)

occur following a large break 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 the large break LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (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 energize their respective buses. 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 at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. 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 High

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Head Safety Injection (HHSI) 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 HHSI 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 ≤ 2200°F for small breaks, and there must be a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks;

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 LBLOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For the small break LOCA analysis, a nominal contained accumulator water volume is used while the large break LOCA analysis samples the accumulator water volume over a given range. For small breaks, the accumulator water volume only affects the mass flow rate of water into the RCS since the tanks do not empty for most break sizes analyzed. The assumed water volume has an insignificant effect upon the peak clad temperature. 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. The safety analysis supports operation with a contained water volume of between 7580 gallons and 7756 gallons per accumulator.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The minimum boron concentration setpoint 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 peak clad temperature analysis is performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity. The large break LOCA analysis samples the accumulator pressure over a given range.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Ref. 1). The large break LOCA containment analyses assume that the accumulator nitrogen is discharged into the containment, which affects transient subatmospheric pressure.

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 large break 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 large break LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

(continued)

BASES

LCO (continued)	For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed when RCS pressure is ≥ 2000 psig, and the limits established in the SRs for contained 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. 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	<u>A.1</u> 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, the accumulators do not discharge following a large main steam line break. Thus, 72 hours is allowed to return the boron concentration to within limits.

BASES

ACTIONS (continued)

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 1 hour. In this Condition, the required contents of two accumulators cannot be assumed to reach the core during a large break LOCA. Due to the severity of the consequences should a large break LOCA occur in these conditions, the 1 hour Completion Time to open the valve, remove power to the valve, 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 time the unit is exposed to a LOCA under these conditions.

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1

If more than one accumulator is inoperable, the unit 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 with power removed, a closed valve could result in not meeting accident analyses assumptions. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2 and SR 3.5.1.3

Borated water volume and nitrogen cover pressure are verified for each accumulator. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.4

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. Sampling the affected accumulator within 6 hours after a 50% increase of indicated level 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. 3).

Although the run of piping between the two accumulator discharge check valves is credited in demonstrating compliance with Technical Specification 3.5.1 minimum accumulator volume requirement, the minimum boron concentration requirement does not apply to this run of piping. Applicable accident analyses have explicitly considered in-leakage from the RCS, and the resulting reduction in boron concentration in this run of piping, which is not sampled.

SR 3.5.1.5

Verification that power is removed from each accumulator isolation valve operator when the RCS pressure is ≥ 2000 psig ensures that an active failure could not result in the 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.5.1.5 (continued) coincident with a LOCA. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. This SR allows power to be supplied to the motor operated isolation valves when RCS pressure is < 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during unit startups or shutdowns.
REFERENCES	1. UFSAR, Chapter 6 and Chapter 15. 2. 10 CFR 50.46. 3. 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. Rupture of a control rod drive mechanism-control rod assembly 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 MSLB where primary cooldown could add enough positive reactivity to achieve criticality and return to significant 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. Within approximately 5 hours, 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 separate subsystems: High Head Safety Injection (HHSI) and Low Head Safety Injection (LHSI). Each subsystem consists of two redundant, 100% capacity trains. 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.

(continued)

BASES

BACKGROUND (continued)

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 major components of each subsystem are the HHSI pumps and the LHSI pumps. Each of the two subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. 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.

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 through normally open, motor operated valves. The discharge from the HHSI pumps combines prior to entering the boron injection tank (BIT) and then divides again into three supply lines, each of which feeds the injection line to one RCS cold leg. The discharge from the LHSI pumps combine and then divide into three supply lines, each of which feeds the injection line to one RCS cold leg. Control valves in the HHSI 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 and preclude pump runout.

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 are used to provide part of the core cooling function.

During the recirculation phase of LOCA recovery, LHSI pump suction is transferred to the containment sump. The LHSI pumps then 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.

(continued)

BACKGROUND (continued)

The HHSI subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as an MSLB. The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

HHSI pumps A and B are capable of being automatically started and are powered from separate emergency buses. HHSI pump C can only be manually started, but can be powered from either of the emergency buses that HHSI pumps A and B are powered from. An interlock prevents HHSI pump C from being powered from both emergency buses simultaneously. For HHSI pump C to be OPERABLE, it must be running since it does not start automatically. In the event of a Safety Injection signal coincident with a loss of offsite power, interlocks prevent automatic operation of two HHSI pumps on the same emergency bus to prevent overloading the emergency diesel generators. HHSI pump C is normally either running, or available but not running. HHSI pump C is normally running if either HHSI pump A or B is inoperable or both are otherwise preferred to not be in operation. HHSI pump C is normally available but not running when either HHSI pump A or B is running.

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. 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 and pump starting determines the time required before pumped flow is available to the core following a LOCA.

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 Reference 1.

BASES

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 for small breaks, and there must be a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks;

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 magnitude of 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 (Refs. 3 and 4). This event establishes the maximum flow requirement for the ECCS pumps. The HHSI pumps are credited in a small break LOCA event. This event relies upon the flow and discharge head 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 loss of offsite power and a single failure disabling one LHSI pump (both EDG trains are assumed to operate due to requirements for modeling full active containment heat removal system operation); and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one Emergency Diesel Generator.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

During the blowdown stage of a large break 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 analysis (Ref. 3). 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 and boron during a small LOCA to maintain core subcriticality. 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 the 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.

In MODES 1, 2, and 3, an ECCS train consists of an HHSI subsystem and a LHSI subsystem. 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 automatically transferring suction to the containment sump.

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 to the RCS hot and cold legs.

(continued)

BASES

LCO (continued)

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

As indicated in the Note, the SI flow paths may 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.

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 has already been 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, unit 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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level," and LCO 3.9.6, "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.

A note has been added to this Action's Completion Time to permit a one-time extension of the Completion Time to 7 days to effect repairs on the Unit 1 "A" LHSI train.

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BASES

ACTIONS

A.1 (continued)

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). This allows increased flexibility in unit 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.

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 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.

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.

BASES

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 in position by removal of power or by key locking the control in the correct position ensures that they cannot change position as a result of an 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.3

With the exception of the operating charging pump, the ECCS pumps are normally in a standby nonoperating mode. As such, some flow path piping has the potential to develop pockets of entrained gases. Plant operating experience and analysis has shown that after proper system filling (following maintenance or refueling outages), some entrained noncondensable gases remain. These gases will form small voids, which remain stable in the system in both normal and transient operation. Mechanisms postulated to increase the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.3 (continued)

void size are gradual in nature, and the system is operated in accordance with procedures to preclude growth in these voids.

To provide additional assurances that the system will function, a verification is performed that the system is sufficiently full of water. The system is sufficiently full of water when the voids and pockets of entrained gases in the ECCS piping are small enough in size and number so as to not interfere with the proper operation of the ECCS. Verification that the ECCS piping is sufficiently full of water can be performed by venting the necessary high point ECCS vents outside containment, using NDE, or using other Engineering-justified means. Maintaining the piping from the ECCS pumps to the RCS sufficiently full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent water hammer, pump cavitation, and pumping of excess noncondensable gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps 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 testing is performed at low flow conditions during quarterly tests and near design flow conditions at least once every 24 months, as required by the Code. The quarterly test will detect gross degradation caused by impeller structural damage or other hydraulic component problems, but is not a good indicator of expected pump performance at high flow conditions. Both tests verify that the measured performance is within an acceptable tolerance of the original pump baseline performance. Additionally, the 24-month comprehensive test verifies that the test flow is greater than or equal to the performance assumed in the safety analysis. Due to limitations in system design, the 24-month test is performed during refueling outages. SRs are specified in the Inservice Testing Program,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.4 (continued)

which encompasses 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 capable of starting automatically starts on receipt of an actual or simulated SI 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.7

Proper throttle valve position is necessary for proper ECCS performance and to prevent pump runout and subsequent component damage. The Surveillance verifies each listed ECCS throttle valve is secured in the correct position. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.8

Periodic inspections of the containment sump components ensure that they are unrestricted and stay in proper operating condition. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Section 3.1.31.
2. 10 CFR 50.46.
3. UFSAR, Section 15.4.1.
4. UFSAR, Section 6.2 and Chapter 15.
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

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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.

In MODE 4, the required ECCS train consists of two separate subsystems: High Head Safety Injection (HHSI) and Low Head Safety Injection (LHSI).

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. The safety analysis assumes that flow from one HHSI pump is manually initiated 10 minutes after the 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.

In MODE 4, 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

(continued)

BASES

LCO (continued)

taking suction from the RWST and transferring suction to the containment sump.

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 to the RCS hot or cold legs.

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, unit 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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level."

ACTIONS

A.1

With no ECCS train OPERABLE, due to the inoperability of the ECCS flow path, the unit 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 unit 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 unit should 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 unit systems or operators.

BASES

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.

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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 pool 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 High Head Safety Injection (HHSI) pumps is supplied via parallel motor operated valves to ensure that at least one 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 in each header 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 either manually or automatically following receipt of the RWST—Low Low level signal. 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.

During normal operation, the LHSI 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.

(continued)

BASES

BACKGROUND (continued)

When the suction for the ECCS pumps is transferred to the containment sump, the recirculation lines are isolated to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the ECCS pumps.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase and Quench Spray System;

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and Recirculation Spray System pumps following 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 to the RCS 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

available volume. The deliverable volume limit is assumed by the Large Break LOCA containment analyses. For the RWST, the deliverable volume is different from the total volume contained. Because of the design of the tank, more water can be contained than can be delivered. The upper RWST volume limit is assumed for pH control after a LBLOCA. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The importance of its value is small because of the boron injection tank (BIT) with a high boron concentration. The maximum boron concentration is an explicit assumption in the inadvertent ECCS actuation analysis, although it is typically a nonlimiting event and the results are very insensitive to boron concentrations. The maximum RWST temperature ensures that the amount of containment cooling provided from the RWST during containment pressurization events is consistent with safety analysis assumptions. The minimum RWST temperature is an assumption in the inadvertent Quench Spray actuation analyses.

For a large break LOCA analysis, the minimum water volume limit of 466,200 gallons and the lower boron concentration limit of 2600 ppm are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core.

The upper limit on boron concentration of 2800 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

In the ECCS analysis, the quench spray temperature is bounded by the RWST lower temperature limit of 40°F. If the lower temperature limit is violated, the quench spray further reduces containment pressure, which decreases the rate at which steam can be vented out the break and increases peak clad temperature. The upper temperature limit of 50°F is bounded by the values used in the small break LOCA analysis and containment OPERABILITY analysis. Exceeding this temperature will result in a higher peak clad temperature, because there is less heat transfer from the core to the injected water for the small break LOCA and higher containment pressures due to reduced quench spray cooling capacity. For the containment response following an MSLB,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	the lower limit on boron concentration and the upper limit on RWST water temperature are used to maximize the total energy release to containment. 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 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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level."
ACTIONS	<u>A.1</u> 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 condition. 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.

BASES

ACTIONS (continued)

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 unit 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 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 unit systems.

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.4.2

The RWST water volume should be verified to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS and Recirculation Spray System pump operation on recirculation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6 and Chapter 15.

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 High Head Safety Injection (HHSI) 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 and precludes HHSI pump runout due to excessive seal injection flow. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during safety injection (SI).

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are assumed to be OPERABLE in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The LOCA analysis establishes the minimum flow for the HHSI pumps. The HHSI pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head requirements at the design point for the HHSI pumps. The steam generator tube rupture and main steam line break event analyses also credit the HHSI 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 of ≤ 30 gpm, with RCS pressure ≥ 2215 psig and ≤ 2255 psig and seal injection (air operated) hand control valve full open, will be limited in such a manner that the ECCS trains will be capable of delivering sufficient water to provide adequate core cooling following a large LOCA, and protect against HHSI pump runout. The analysis conservatively neglects the contribution from seal injection to the RCS. This conservatism bounds the minor effect of instrument uncertainty, so instrument uncertainties have not been included in the derivation of the flow (30 gpm) and RCS pressure (≥ 2215 psig and ≤ 2255 psig) setpoints. The flow limit also ensures that the HHSI pumps will deliver

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the HHSI 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 HHSI pump injection flow is directed to the RCS via the injection points and to prevent pump runout.

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 as specified in this LCO. The HHSI pump discharge header 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 RCS pressure result in a conservative valve position should RCS pressure decrease. The additional modifier of this LCO, the seal injection (air operated) hand 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 path resistance limit is established. It is this resistance limit that is used in the accident analyses.

The limit on seal injection flow, combined with the RCS pressure limit and an open wide condition of the seal injection hand control valve, must be met to render the ECCS OPERABLE. If these conditions are not met, the ECCS flow to the core could be less than that 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

(continued)

BASES

APPLICABILITY (continued)

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.

ACTIONS

A.1

With the seal injection flow exceeding its limit, the amount of charging flow available to the RCS may be reduced or, following a LOCA, pump runout could occur. Under this Condition, action must be taken to restore the flow to below its limit. The operator has 4 hours from the time the flow is known to be above 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 unit 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 unit safety systems or operators. Continuing the unit 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 proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1 (continued)

As noted, the Surveillance is not required to be performed until 4 hours after the RCS pressure has stabilized within a ± 20 psi 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 6 and Chapter 15.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.6 Boron Injection Tank (BIT)

BASES

BACKGROUND

The BIT is the primary means of quickly introducing negative reactivity into the Reactor Coolant System (RCS) on a safety injection (SI) signal.

The main flow path through the Boron Injection Tank is from the discharge of the High Head Safety Injection (HHSI) pumps through lines equipped with a flow element and two valves in parallel that open on an SI signal. The valves can be operated from the main control board. The valves and flow elements have main control board indications. Downstream of these valves, the flow enters the BIT (Ref. 1).

The BIT is a stainless steel clad tank containing concentrated boric acid. Two trains of strip heaters are mounted on the tank to keep the temperature of the boric acid solution above the precipitation point. The strip heaters are controlled by temperature elements located near the bottom of the BIT. The temperature elements also activate High and Low temperature alarms in the Control Room. In addition to the strip heaters on the BIT, there is a recirculation system with a heat tracing system, including the piping section between the motor operated isolation valves, which further ensures that the boric acid stays in solution. The entire contents of the BIT are injected when required; thus, the contained and deliverable volumes are the same.

During normal operation, a boric acid transfer pump provides recirculation between the boric acid tank and the BIT. On receipt of an SI signal, the recirculation line valves close. Flow to the BIT is then supplied from the HHSI pumps. The solution of the BIT is injected into the RCS through the RCS cold legs.

APPLICABLE SAFETY ANALYSES

During a main steam line break (MSLB) or loss of coolant accident (LOCA), the BIT provides an immediate source of concentrated boric acid that quickly introduces negative reactivity into the RCS.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The contents of the BIT are not credited for core cooling or immediate boration in the LOCA analysis, but are for post LOCA recovery. The BIT maximum boron concentration of 15,750 ppm is used to determine the minimum time for hot leg recirculation switchover. The minimum boron concentration of 12,950 ppm is used to determine the minimum mixed mean sump boron concentration for post LOCA shutdown requirements.

For the MSLB, the BIT is the primary mechanism for injecting boron into the core to counteract the positive increases in reactivity caused by an RCS cooldown. The MSLB core response analysis conservatively assumes a 0 ppm minimum boron concentration of the BIT, which also affects the departure from nucleate boiling design analysis. The MSLB containment response analysis conservatively assumes a 2000 ppm minimum boron concentration of the BIT. Reference to the LOCA and MSLB analyses is used to assess changes to the BIT to evaluate their effect on the acceptance limits contained in these analyses.

The minimum temperature limit of 115°F for the BIT ensures that the solution does not reach the boric acid precipitation point. The temperature of the solution is monitored and alarmed on the main control board.

The BIT boron concentration limits are established to ensure that the core remains subcritical during post LOCA recovery. The BIT will counteract any positive increases in reactivity caused by an RCS cooldown.

The BIT water volume of 900 gallons is used to ensure that the appropriate quantity of highly borated water with sufficient negative reactivity is injected into the RCS to shut down the core following an MSLB, to determine the hot leg recirculation switchover time, and to safeguard against boron precipitation.

The BIT satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO establishes the minimum requirements for contained volume, boron concentration, and temperature of the BIT inventory. This ensures that an adequate supply of borated water is available in the event of a LOCA or MSLB to maintain the reactor subcritical following these accidents.

(continued)

BASES

LCO (continued)

To be considered OPERABLE, the limits established in the SR for water volume, boron concentration, and temperature must be met.

APPLICABILITY

In MODES 1, 2, and 3, the BIT OPERABILITY requirements are consistent with those of LCO 3.5.2, "ECCS—Operating."

In MODES 4, 5, and 6, the respective accidents are less severe, so the BIT is not required in these lower MODES.

ACTIONS

A.1

If the required volume is not present in the BIT, both the hot leg recirculation switchover time analysis and the boron precipitation analysis may not be correct. Under these conditions, prompt action must be taken to restore the volume to above its required limit to declare the tank OPERABLE, or the unit must be placed in a MODE in which the BIT is not required.

The BIT boron concentration is considered in the hot leg recirculation switchover time analysis, the boron precipitation analysis, and may effect the reactivity analysis for an MSLB. If the concentration were not within the required limits, these analyses could not be relied on. Under these conditions, prompt action must be taken to restore the concentration to within its required limits, or the unit must be placed in a MODE in which the BIT is not required.

The BIT temperature limit is established to ensure that the solution does not reach the boric acid crystallization point. If the temperature of the solution drops below the minimum, prompt action must be taken to raise the temperature and declare the tank OPERABLE, or the unit must be placed in a MODE in which the BIT is not required.

The 1 hour Completion Time to restore the BIT to OPERABLE status is consistent with other Completion Times established for loss of a safety function and ensures that the unit will not operate for long periods outside of the safety analyses.

ACTIONS (continued)

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

When Required Action A.1 cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Six hours is a reasonable time, based on operating experience, to reach MODE 3 from full power conditions and to be borated to the required SDM without challenging unit systems or operators. Borating to the required SDM assures that the unit is in a safe condition, without need for any additional boration.

After determining that the BIT is inoperable and the Required Actions of B.1 and B.2 have been completed, the tank must be returned to OPERABLE status within 7 days. These actions ensure that the unit will not be operated with an inoperable BIT for a lengthy period of time. It should be noted, however, that changes to applicable MODES cannot be made until the BIT is restored to OPERABLE status, except as provided by LCO 3.0.4.

C.1

Even though the RCS has been borated to a safe and stable condition as a result of Required Action B.2, either the BIT must be restored to OPERABLE status (Required Action C.1) or the unit must be placed in a condition in which the BIT is not required (MODE 4). The 12 hour Completion Time to reach MODE 4 is reasonable, based on operating experience and normal cooldown rates, and does not challenge unit safety systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.6.1

Verification that the BIT water temperature is at or above the specified minimum temperature will identify a temperature change that would approach the acceptable limit. The solution temperature is also monitored by an alarm that provides further assurance of protection against low temperature. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.6.2

Verification that the BIT contained volume is above the required limit assures that this volume will be available for quick injection into the RCS. The 900 gallon limit corresponds to the BIT being completely full. Methods of verifying that the BIT is completely full include venting from the high point vent, and recirculation flow with the Boric Acid Storage Tanks. If the volume is too low, the BIT would not provide enough borated water to ensure subcriticality during recirculation or to provide additional core shutdown margin following an MSLB. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.5.6.3

Verification that the boron concentration of the BIT is within the required band ensures that the reactor remains subcritical following a LOCA; it limits return to power following an MSLB, and maintains the resulting sump pH in an acceptable range so that boron precipitation will not occur in the core. In addition, the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized.

The BIT is in a recirculation loop that provides continuous circulation of the boric acid solution through the BIT and the boric acid tank (BAT). There are a number of points along the recirculation loop where local samples can be taken. The actual location used to take a sample of the solution is specified in the unit Surveillance procedures. Sampling from the BAT to verify the concentration of the BIT is not recommended, since this sample may not be homogenous and the boron concentration of the two tanks may differ.

The sample should be taken from the BIT or from a point in the flow path of the BIT recirculation loop.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6 and Chapter 15.

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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 hemispherical 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";

BASES

BACKGROUND (continued)

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed; and

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

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting 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. 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% of containment air weight per day in the safety analyses at P_a (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 prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time the applicable leakage limits must be met.

(continued)

BASES

LCO (continued)

Compliance with this LCO will ensure a containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock (LCO 3.6.2) and purge valves with resilient seals (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

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 3.9.4, "Containment Penetrations."

ACTIONS

<u>A.1</u>

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.

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

If containment 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 unit systems.

BASES

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 and purge valves with resilient seal leakage limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required Containment Leakage Rate Testing Program, leakage test is required to be $\leq 0.6\ L_a$ 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 an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies 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 15.

3. UFSAR, Section 6.2.

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, one of which is 7 ft in diameter, the other 5.75 ft in diameter, with a door at each end. The 5.75 ft diameter equipment hatch escape air lock is an integral part of the containment equipment hatch. 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. 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 gasketed seals and local leakage rate testing capability to ensure pressure integrity. The inner and outer door of the 7 ft diameter personnel air lock include an 18 inch diameter emergency manway. The manways contain double gasketed seals and local leak rate testing capability to ensure pressure integrity. The manways are to be used only for emergency entrance or exit from the air lock. Operation of the manways of the 7 ft personnel air lock is controlled administratively.

The 7 ft personnel air lock is provided with limit switches on both doors that provide control room alarm of inside or outside door operation. Outside access to the 5.75 ft equipment hatch escape air lock is controlled by an alarmed door to the space outside containment which provides access to the air lock.

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.

BASES

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 3). In the analysis of each of these accidents, 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 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. 1), 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 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. Opening or closing of the manways of the 7 ft personnel air lock is treated in the same manner as opening or closing of the associated door. The interlock allows only one air lock door of an air lock to be opened at one time. Operation of the manways of the 7 ft personnel air lock is controlled administratively. These provisions ensure 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 entry into or exit from containment.

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 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 3.9.4, "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. It is preferred that the 7 ft personnel air lock be used for access to Containment due to the size and configuration of the 5.75 ft equipment hatch escape air locks. The equipment hatch escape air lock is typically only used in case of emergency. This 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 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, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

BASES

ACTIONS (continued)

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.

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 if the air lock has an inoperable door. This 7 day restriction

(continued)

BASES

ACTIONS

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

begins when the air lock door is discovered inoperable. 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 unit 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 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 unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of TS 5.5.15 Containment Leakage Rate Testing Program. This SR reflects the overall air lock leakage rate testing acceptance criteria with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage limits do not exceed the allowed fraction of the overall containment leakage rate required by the Technical Specifications. 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 are applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

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 when combined with administrative procedures. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES	1. 10 CFR 50, Appendix J, Option B.
	2. UFSAR, Section 6.2.
	3. UFSAR, Chapter 15.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves listed in TRM Tables 4.1-1 (Unit 1) and 4.1-2 (Unit 2) 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. Automatic valves designed to close without operator action following an accident are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

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.

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.

(continued)

BASES

BACKGROUND (continued)

<u>Containment Purge System (36 inch purge and exhaust valves, 18 inch containment vacuum breaking valve, and 8 inch purge bypass valve)</u>

The Containment Purge System operates to supply outside air into the containment for ventilation and cooling or 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 isolation valves. Because of their large size, the 36 inch purge valves are not qualified for automatic closure from their open position under Design Basis Accident (DBA) conditions. Therefore, the 36 inch purge valves are maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained. The 18 inch containment vacuum breaking valve and 8 inch bypass valve are also maintained closed in MODES 1, 2, 3, and 4.

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 are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 1). In the analyses for each of these accidents, 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 36 inch purge and exhaust valves are closed at event initiation.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Containment isolation valves listed in TRM Tables 4.1-1 (Unit 1) and 4.1-2 (Unit 2) 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 36, 18, and 8 inch purge valves must be maintained locked, sealed, or otherwise secured closed. The valves covered by this LCO are listed along with their associated stroke times in the Technical Requirements Manual (Ref. 2). The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves/devices are those listed in Reference 2. Purge valves with resilient seals must meet additional leakage rate requirements. The other 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.
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 3.9.4, "Containment Penetrations."

BASES

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 36 inch purge and exhaust valve, 18 inch containment vacuum breaking valve, 8 inch purge bypass valve, and steam jet air ejector suction 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 fact that the 36 inch valves are not qualified for automatic closure from their open position under DBA conditions and that these and the other penetrations listed as excepted 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 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.

In the event the leakage for a containment penetration flow path results in exceeding the overall containment leakage rate acceptance criteria, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

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

In the event one containment isolation valve in one or more penetration flow paths is inoperable, except for purge valve leakage not within limit, 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

de-activated automatic containment isolation valve, a closed manual valve, a blind flange, or 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.

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, through a system walkdown, 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 only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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.

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, except for purge valve leakage not within limit, 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.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

BASES

ACTIONS (continued)

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, with the exception of valves specified in Reference 4. 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.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements of Reference 3. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

With the purge valve penetration leakage rate (SR 3.6.3.4) not within limit, the assumptions of the safety analyses are not met. Therefore, the leakage must be restored to within limit. Restoration can be accomplished by isolating the penetration(s) that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 24 hour Completion Time for purge valve penetration leakage is acceptable considering the purge valves remain closed so that a gross breach of containment does not exist.

E.1 and E.2

If the Required Actions and associated Completion Times are 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 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 3.6.3.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 3.6.3.2

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 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2 (continued)

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 3.6.3.3

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

SR 3.6.3.4

For containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B, is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types.

This SR must be performed prior to entering MODE 4 from MODE 5 after containment vacuum has been broken. This Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that occurring to a valve that has not been opened). This Frequency will ensure that each time these valves are cycled they will be leak tested.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.5

Automatic containment isolation valves close on a 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 will actuate to its isolation position on a containment isolation signal. Check valves which are containment isolation valves are not considered automatic valves for the purpose of this Surveillance as they do not receive a 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.3.6

The check valves that serve a containment isolation function are weight or spring loaded to provide positive closure in the direction of flow. This ensures that these check valves will remain closed when the inside containment atmosphere returns to subatmospheric conditions following a DBA. SR 3.6.3.6 verifies the operation of the check valves that are not testable during unit operation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.
2. Technical Requirements Manual.
3. Standard Review Plan 6.2.4.
4. UFSAR, Section 6.2.4.2.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	Containment air partial pressure is a process variable that is monitored and controlled. The containment air partial pressure is maintained as a function of refueling water storage tank temperature and service water temperature according to Figure 3.6.4-1 of the LCO, to ensure that, following a Design Basis Accident (DBA), the containment would depressurize to less than 2.0 psig in 1 hour and to subatmospheric pressure within 6 hours. Controlling containment partial pressure within prescribed limits also prevents the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of an inadvertent actuation of the Quench Spray (QS) System. Controlling containment air partial pressure limits within prescribed limits ensures adequate net positive suction head (NPSH) for the recirculation spray and low head safety injection pumps following a DBA. The containment internal air partial pressure limits of Figure 3.6.4-1 are derived from the input conditions used in the containment DBA analyses. Limiting the containment internal air partial pressure and temperature in turn limits the pressure that could be expected following a DBA, thus ensuring containment OPERABILITY. Ensuring containment OPERABILITY limits leakage of fission product radioactivity from containment to the environment.
APPLICABLE SAFETY ANALYSES	Containment air partial pressure is an initial condition used in the containment DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered relative to containment pressure are the loss of coolant accident (LOCA) and steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure transients. DBAs are assumed not to occur simultaneously or consecutively. The postulated DBAs are analyzed assuming degraded containment Engineered Safety Feature (ESF) systems (i.e., assuming no offsite power and the loss of one emergency diesel generator, which is the worst case single active failure, resulting in one train of the QS System and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

one train of the Recirculation Spray System becoming inoperable). The containment analysis for the DBA (Ref. 1) shows that the maximum peak containment pressure results from the limiting design basis SLB.

The maximum design internal pressure for the containment is 45.0 psig. The LOCA and SLB analyses establish the limits for the containment air partial pressure operating range. The initial conditions used in the containment design basis LOCA analyses were an air partial pressure of 12.3 psia and an air temperature of 115°F. This resulted in a maximum peak containment internal pressure of 42.7 psig, which is less than the maximum design internal pressure for the containment. The SLB analysis resulted in a maximum peak containment internal pressure of 43.0 psig, which is less than the maximum design internal pressure for the containment.

The containment was also designed for an external pressure load of 9.2 psid (i.e., a design minimum pressure of 5.5 psia). The inadvertent actuation of the QS System was analyzed to determine the reduction in containment pressure (Ref. 1). The initial conditions used in the analysis were 10.3 psia and 115°F. This resulted in a minimum pressure inside containment of 8.6 psia, which is considerably above the design minimum of 5.5 psia.

Controlling containment air partial pressure limits within prescribed limits ensures adequate NPSH for the recirculation spray and low head safety injection pumps following a DBA. The minimum containment air partial pressure is an initial condition for the NPSH analyses.

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. For the reflood phase calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50.46 (Ref. 2).

The radiological consequences analysis demonstrates acceptable results provided the containment pressure decreases to 2.0 psig in 1 hour and does not exceed 2.0 psig

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

for the interval from 1 to 6 hours following the Design Basis Accident (Ref. 3). Beyond 6 hours the containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Maintaining containment pressure within the limits shown in Figure 3.6.4-1 of the LCO ensures that in the event of a DBA the resultant peak containment accident pressure will be maintained below the containment design pressure. 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 QS System. The LCO limits also ensure the containment structure will depressurize to less than 2.0 psig in 1 hour and to subatmospheric pressure within 6 hours following a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within design basis 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 Reactor Coolant System 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 air partial pressure is not within the limits of the LCO, containment pressure 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

ACTION (continued)	B.1 and B.2 If containment air partial pressure cannot be restored to within limits 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 unit systems.
SURVEILLANCE REQUIREMENTS	SR 3.6.4.1 Verifying that containment air partial pressure is within limits ensures that operation remains within the limits assumed in the containment analysis. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 6.2. 2. 10 CFR 50.46. 3. UFSAR, Section 15.4.1.7.

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 limit is 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 Containment Spray systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy which must be removed, resulting in a higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit 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 that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

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 postulated DBAs are analyzed with regard to containment

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Engineered Safety Feature (ESF) systems, assuming no offsite power and the loss of one emergency diesel generator, which is the worst case single active failure, resulting in one train of the Quench Spray (QS) System and Recirculation Spray System being rendered inoperable. The postulated SLB events are analyzed without credit for the RS system.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses is 115°F. This resulted in a maximum containment air temperature of 309°F. The design temperature is 280°F.

The temperature upper limit is used to establish the environmental qualification operating envelope for containment. The maximum peak containment air temperature was calculated to exceed the containment design temperature for a relatively short period of time during the transient. The basis of the containment design temperature, however, is to ensure the performance of safety related equipment inside containment (Ref. 2). Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design temperature was short enough that there would be no adverse effect on equipment inside containment assumed to mitigate the consequences of the DBA. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The temperature upper limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the QS System (Ref. 1).

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 pressure is an SLB. The temperature upper limit is used in the SLB analysis to ensure that, in the event of an accident, the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

During an SLB, with an initial containment average temperature less than or equal to the LCO temperature limits, the resultant peak accident temperature exceeds containment design temperature for a relatively short period of time, but otherwise is maintained below the containment design temperature. As a result, the ability of containment to perform its design function is ensured.

APPLICABILITY

In MODES 1, 2, 3, and 4, an SLB could cause an accidental release of radioactive material to the environment or a reactivity excursion. 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 limits 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 unit systems.

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 limits assumed for the containment analyses. In order to determine the containment average air temperature,

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.5.1 (continued) a weighted average is calculated using measurements taken at locations within containment selected to provide a representative sample of the overall containment atmosphere. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 6.2. 2. 10 CFR 50.49.

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 2.0 psig in 1 hour and to subatmospheric pressure within 6 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 equal capacity, each capable of meeting the design bases. Each train includes a spray pump, a dedicated spray header, nozzles, valves, and piping. 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 QS System also provides flow to the Inside RS pumps to improve the net positive suction head available.

The Chemical Addition System supplies a sodium hydroxide (NaOH) solution into the spray. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge iodine fission products from the containment atmosphere. The NaOH added to the spray also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

(continued)

BASES

BACKGROUND (continued)

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 less than the containment design values and depressurize the containment structure to less than 2.0 psig in 1 hour and to subatmospheric pressure within 6 hours following a DBA.

The QS 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.

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 containment ESF Systems, assuming no offsite power and the loss of one emergency diesel generator, which is the worst case single active failure, resulting in one train of the QS System and the RS System inoperable. The postulated SLB events are analyzed without credit for the RS system.

During normal operation, the containment internal pressure is varied, along with other parameters, to maintain the capability to depressurize the containment to less than 2.0 psig in 1 hour and to subatmospheric pressure within 6 hours after a DBA. This capability and the variation of containment pressure during a DBA are functions of the service water temperature, the RWST water temperature, and the containment air temperature.

The DBA analyses (Ref. 1) show that the maximum peak containment pressure of 43.0 psig results from the SLB analysis and is calculated to be less than the containment design pressure. The maximum peak containment atmosphere temperature of 309°F results from the SLB analysis and was calculated to exceed the containment design temperature for a relatively short period of time during the transient. The basis of the containment design temperature, however, is to ensure OPERABILITY of safety related equipment inside containment (Ref. 2). Thermal analyses show that the time interval during which the containment atmosphere temperature

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

exceeded the containment design temperature was short enough that there would be no adverse effect on equipment inside containment assumed to mitigate the consequences of the DBA.

Therefore, it is concluded that the calculated transient containment atmosphere temperatures are acceptable for the SLB.

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 spray nozzles. A delayed response time initiation provides conservative analyses of peak calculated containment temperature and pressure responses. The QS System total response time of 70 seconds after Containment Pressure—High High comprises the signal delay, diesel generator startup time, and system startup time, including pipe fill 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 50.46 (Ref. 3).

Inadvertent actuation of the QS System is evaluated in the analysis, and the resultant reduction in containment pressure is calculated. The maximum calculated reduction in containment pressure results in containment pressures within the design containment minimum pressure.

The radiological consequences analysis demonstrates acceptable results provided the containment pressure decreases to 2.0 psig in 1 hour and does not exceed 2.0 psig for the interval from 1 to 6 hours following the Design Basis Accident (Ref. 4). Beyond 6 hours the containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

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. In addition, one QS System train, with spray pH adjusted by the contents of the chemical addition tank, is required to scavenge iodine fission products from the containment atmosphere and ensure their retention in the containment sump water. To ensure that these requirements 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 of QS will operate, assuming that the worst case single active failure occurs.

Each QS train includes a spray pump, a dedicated spray header, 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 available in this degraded condition are capable of providing 100% of the heat removal and iodine removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal and iodine 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 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 3.6.6.1

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, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.2

Verifying that each QS pump's developed head at the flow test point is greater than or equal to the required developed head ensures that QS pump performance is consistent with the safety analysis assumptions. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref. 5). Since the QS System pumps cannot be tested with flow through the spray headers, they are tested on recirculation 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.

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 Pressure high-high signal.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.3 and SR 3.6.6.4 (continued)

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.6.5

With the quench spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections or an inspection of the nozzles can be performed. 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 and the non-corrosive design of the system, a test performed following maintenance which could result in nozzle blockage is considered adequate to detect obstruction of the nozzles.

REFERENCES

1. UFSAR, Section 6.2.
2. 10 CFR 50.49.
3. 10 CFR 50.46.
4. UFSAR, Section 15.4.1.7.
5. 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 2.0 psig in 1 hour and to subatmospheric pressure within 6 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 equal capacity, each capable of meeting the design and accident analysis bases. Each train includes one RS subsystem outside containment and one RS subsystem inside containment. Each subsystem consists of one approximately 50% capacity spray pump, one spray cooler, one 180° coverage spray header, nozzles, valves, piping, instrumentation, and controls. Each outside RS subsystem also includes a casing cooling pump with its own valves, piping, instrumentation, and controls. The two outside RS subsystems' spray pumps are located outside containment and the two inside RS subsystems' spray pumps are located inside containment. Each RS train (one inside and one outside RS subsystem) is powered from a separate Engineered Safety Features (ESF) bus. Each train of the RS System provides adequate spray coverage to meet the system design requirements for containment heat and iodine fission product removal. Two spray pumps are required to provide 360° of containment spray coverage assumed in the accident analysis. One train of RS or two outside RS subsystems will provide the containment spray coverage and required flow.

The two casing cooling pumps and common casing cooling tank are designed to increase the net positive suction head (NPSH) available to the outside RS pumps by injecting cold water into the suction of the spray pumps. They are also beneficial to the containment depressurization analysis. The casing cooling tank contains at least 116,500 gal of chilled and borated water. Each casing cooling pump supplies one outside spray pump with cold borated water from the casing

(continued)

BASES

BACKGROUND (continued)

cooling tank. The casing cooling pumps are considered part of the outside RS subsystems. Each casing cooling pump is powered from a separate ESF bus.

The inside RS subsystem pump NPSH is increased by reducing the temperature of the water at the pump suction. Flow is diverted from the QS system to the suction of the inside RS pump on the same safety train as the quench spray pump supplying the water.

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. Upon receipt of a High-High containment pressure signal, the two casing cooling pumps start, the casing cooling discharge valves open, and the RS pump suction and discharge valves receive an open signal to assure the valves are open. Refueling water storage tank (RWST) Level—Low coincident with Containment Pressure—High High provides the automatic start signal for the inside RS and outside RS pumps. Once the coincidence logic is satisfied, the outside RS pumps start immediately and the inside RS pumps start after a 120-second delay. The delay time is sufficient to avoid simultaneous starting of the RS pumps on the same emergency diesel generator. The coincident trip ensures that adequate water inventory is present in the containment sump to meet the RS sump strainer functional requirements following a loss of coolant accident (LOCA). The RS system is not required for steam line break (SLB) mitigation. 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 service water in the spray coolers.

The Chemical Addition System supplies a sodium hydroxide (NaOH) solution to the RWST water supplied to the suction of the QS System pumps. The NaOH added to the QS System spray 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. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

(continued)

BASES

BACKGROUND (continued)

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 2.0 psig in 1 hour and to subatmospheric pressure within 6 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.

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered are the LOCA and the 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 no offsite power and the loss of one emergency diesel generator, which is the worst case single active failure for containment depressurization, resulting in one train of the QS and RS systems being rendered inoperable (Ref. 1). The postulated SLB events are analyzed without credit for the RS system.

The peak containment pressure following a high energy line break is affected by the initial total pressure and temperature of the containment atmosphere and the QS System operation. Maximizing the initial containment total pressure and average atmospheric temperature maximizes the calculated peak pressure. The heat removal effectiveness of the QS System spray is dependent on the temperature of the water in the RWST. The time required to depressurize the containment and the capability to maintain it depressurized below atmospheric pressure depend on the functional performance of the QS and RS systems and the service water temperature. When the Service Water temperature is elevated, it is more difficult to depressurize the containment to less than 2.0 psig in 1 hour and to subatmospheric pressure within 6 hours since the heat removal effectiveness of the RS System is limited.

During normal operation, the containment internal pressure is varied to maintain the capability to depressurize the containment to less than 2.0 psig in 1 hour and to subatmospheric pressure within 6 hours after a DBA. This

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

capability and the variation of containment pressure are functions of service water temperature, RWST water temperature, and the containment air temperature.

The DBA analyses show that the maximum peak containment pressure of 43.0 psig results from the SLB analysis and is calculated to be less than the containment design pressure. The maximum 309°F peak containment atmosphere temperature results from the SLB analysis and is calculated to exceed the containment design temperature for a relatively short period of time during the transient. The basis of the containment design temperature, however, is to ensure OPERABILITY of safety related equipment inside containment (Ref. 2). Thermal analyses show that the time interval during which the containment atmosphere temperature exceeds the containment design temperature is short enough that there would be no adverse effect on equipment inside containment. Therefore, it is concluded that the calculated transient containment atmosphere temperatures are acceptable for the SLB and LOCA.

The RS System actuation model from the containment analysis is based upon a response associated with exceeding the Containment Pressure—High High signal setpoint and RWST level decreasing below the RWST Level—Low setpoint. The containment analysis models account conservatively for instrument uncertainty for the Containment Pressure—High High setpoint and the RWST Level—Low setpoint. The RS System's total response time is determined by the time to satisfy the coincidence logic, the timer delay for the inside RS pumps, pump startup time, and piping fill 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 50.46 (Ref. 3).

The radiological consequences analysis demonstrates acceptable results provided the containment pressure decreases to 2.0 psig in 1 hour and does not exceed 2.0 psig for the interval from 1 to 6 hours following the Design Basis

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Accident (Ref. 4). Beyond 6 hours the containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

The RS System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, one train (one inside and one outside RS subsystem in the same train) or two outside RS subsystems of the RS System are required to provide the minimum heat removal capability assumed in the safety analysis. To ensure that this requirement is met, four RS subsystems and the casing cooling tank must be OPERABLE. This will ensure that at least one train will operate assuming the worst case single failure occurs, which is no offsite power and the loss of one emergency diesel generator. Inoperability of the casing cooling tank, the casing cooling pumps, the casing cooling valves, piping, instrumentation, or controls, or of the QS System requires an assessment of the effect on RS subsystem OPERABILITY.

Each RS train consists of one RS subsystem outside containment and one RS subsystem inside containment. Each RS subsystem includes one spray pump, one spray cooler, one 180° coverage spray header, nozzles, valves, piping, instrumentation, and controls to ensure an OPERABLE flow path capable of taking suction from the containment sump.

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

A.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 at least 100% of the heat removal needs (i.e., approximately 150% when one RS subsystem is inoperable)

(continued)

BASES

ACTIONS

A.1 (continued)

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.

B.1 and C.1

With two of the required RS subsystems inoperable either in the same train, or both inside RS subsystems, 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 and 360° containment spray coverage 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.

D.1

With the casing cooling tank inoperable, the NPSH available to both outside RS subsystem pumps may not be sufficient. The inoperable casing cooling tank 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 casing cooling tank does not affect the OPERABILITY of the inside RS subsystem pumps. The effect on NPSH of the outside RS pumps must be assessed as part of outside RS pump OPERABILITY. The 72 hour Completion Time was chosen based on the same reasons as given in Required Action B.1.

E.1 and E.2

If the inoperable RS subsystem(s) or the casing cooling tank 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 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 unit systems. The extended interval to reach

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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.

F.1

With an inoperable inside RS subsystem in one train, and an inoperable outside RS subsystem in the other train, only 180° containment spray coverage is available. This condition is outside accident analysis. With three or more RS subsystems inoperable, the unit is in a condition outside the accident analysis. With two inoperable outside RS subsystems, less than 100% of required RS flow is available. Therefore, in all three cases, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying that the casing cooling tank solution temperature is within the specified tolerances provides assurance that the water injected into the suction of the outside RS pumps will increase the NPSH available as per design. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.2

Verifying the casing cooling tank contained borated water volume provides assurance that sufficient water is available to support the outside RS subsystem pumps during the time they are required to operate. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.3

Verifying the boron concentration of the solution in the casing cooling tank provides assurance that borated water added from the casing cooling tank to RS subsystems will not dilute the solution being recirculated in the containment sump. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.4

Verifying the correct alignment of manual, power operated, and automatic valves, excluding check valves, in the RS System and casing cooling tank 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, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.5

Verifying that each RS and casing cooling pump's developed head at the flow test point is greater than or equal to the required developed head ensures that these pumps' performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref. 5). Since the RS System pumps cannot be tested with flow through the spray headers, they are tested on recirculation 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 3.6.7.6

These SRs ensure that each automatic valve actuates and that the casing cooling pumps start upon receipt of an actual or simulated High-High containment pressure signal. The RS pumps are verified to start with an actual or simulated RWST Level—Low signal coincident with a Containment Pressure—High High signal. The start delay times for the inside RS pumps are also verified. 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.7

Periodic inspections of the containment sump components ensure that they are unrestricted and stay in proper operating condition. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.8

This SR ensures that each spray nozzle is unobstructed and that spray coverage of the containment will meet its design bases objective. Either an inspection of the nozzles or an air or smoke test is performed through each spray header. Due to the passive design of the spray header and its normally dry state, a test performed following maintenance which could result in nozzle blockage is considered adequate for detecting obstruction of the nozzles.

REFERENCES

1. UFSAR, Section 6.2.
2. 10 CFR 50.49.
3. 10 CFR 50.46.
4. UFSAR, Section 15.4.1.7.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Chemical Addition System

BASES

BACKGROUND

The Chemical Addition System is a subsystem of the Quench Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA).

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, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Because of its stability when exposed to radiation and elevated temperature, sodium hydroxide (NaOH) is the preferred spray additive. The NaOH added to the spray also ensures a pH value of between 7.0 and 8.5 of the solution recirculated from the containment sump. This pH band minimizes the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

The Chemical Addition System consists of one chemical addition tank, two parallel redundant motor operated valves in the line between the chemical addition tank and the refueling water storage tank (RWST), instrumentation, and a recirculation pump. The NaOH solution is added to the spray water by a balanced gravity feed from the chemical addition tank through the connecting piping into a weir within the RWST. There, it mixes with the borated water flowing to the spray pump suction. Because of the hydrostatic balance between the two tanks, the flow rate of the NaOH is controlled by the volume per foot of height ratio of the two tanks. This ensures a spray mixture pH that is ≥ 8.5 and ≤ 10.5.

The Quench Spray System actuation signal opens the valves from the chemical addition tank to the spray pump suctions or the quench spray pump start signal opens the valves from the chemical addition tank after a 5 minute delay. The 12% to 13% NaOH solution is drawn into the spray pump suctions. The chemical addition tank capacity provides for the addition of NaOH solution to all of the water sprayed from the RWST into containment. The percent solution and volume of solution

(continued)

BASES

BACKGROUND (continued)	sprayed into containment ensures a long term containment sump pH of ≥ 7.0 and ≤ 8.5. This ensures the continued iodine retention effectiveness of the sump water during the recirculation phase of spray operation and also minimizes the occurrence of chloride induced stress corrosion cracking of the stainless steel recirculation piping. Maintaining the sump fluid pH less than or equal to 8.5 ensures that there is adequate NPSH available to the ECCS and RSS pumps with post-LOCA debris and chemical precipitant loading on the containment sump strainer.
APPLICABLE SAFETY ANALYSES	The Chemical Addition System is essential to the removal of airborne iodine within containment following a DBA. Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its analysis value volume following the accident. The plant accident dose calculations use an effective containment coverage of 70% of the containment volume. The containment safety analyses implicitly assume that the containment atmosphere is so turbulent following an accidental release of high energy fluids inside containment that, for heat removal purposes, the containment volume is effectively completely covered by spray. The DBA response time assumed for the Chemical Addition System is based on the Chemical Addition System isolation valves beginning to open 5 minutes after a QS pump start. The DBA analyses assume that one train of the Quench Spray System is inoperable and that the entire chemical addition tank volume is added through the remaining Quench Spray System flow path. The Chemical Addition System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The Chemical Addition System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the volume and concentration of the chemical addition solution must be sufficient to provide NaOH injection into the spray flow until the Quench Spray System has completed pumping water from the RWST to the containment sump, and to raise the

(continued)

BASES

LCO (continued)	average spray solution pH to a level conducive to iodine removal, namely, to between 8.5 and 10.5. This pH range maximizes the effectiveness of the iodine removal mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. In addition, it is essential that valves in the Chemical Addition System flow paths are properly positioned and that automatic valves are capable of activating to their correct positions.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Chemical Addition System. The Chemical Addition 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 Chemical Addition System is not required to be OPERABLE in MODE 5 or 6.
ACTIONS	A.1 If the Chemical Addition System is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the Quench Spray System flow for iodine removal enhancement is reduced in this condition. The Quench Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA. The 72 hour Completion Time takes into account the ability of the Quench Spray System to remove iodine at a reduced capability using the redundant Quench Spray flow path capabilities and the low probability of the worst case DBA occurring during this period. B.1 and B.2 If the Chemical Addition System 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 84 hours. The allowed Completion Time of 6 hours is reasonable, based

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Chemical Addition 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

Verifying the correct alignment of Chemical Addition System manual, power operated, and automatic valves in the chemical addition flow path provides assurance that the system is able to provide additive to the Quench Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the chemical addition tank must provide a sufficient volume of spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Chemical Addition System. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.3

This SR provides verification, by chemical analysis, of the NaOH concentration in the chemical addition tank and is sufficient to ensure that the spray solution being injected

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.8.3 (continued)

into containment is at the correct pH level. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.4

This SR provides verification that each automatic valve in the Chemical Addition System flow path actuates to its correct position. 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.5

To ensure that the correct pH level is established in the borated water solution provided by the Quench Spray System, flow from the Chemical Addition System is verified draining solution from the RWST and chemical addition tank through the drain lines in the cross-connection between the tanks. This SR provides assurance that the correct amount of NaOH will be metered into the flow path upon Quench Spray System initiation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

None

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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 and Circulating Water System, is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the UFSAR, Section 10.3.1 (Ref. 1). The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered lift settings, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered lift settings reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine reactor trip. These lift settings are for ambient conditions of the valve 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.

APPLICABLE SAFETY ANALYSES

The design basis for the capacity of the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 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 the UFSAR, Section 15.2 (Ref. 3). Of these, the full power turbine trip without steam dump is typically the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

(continued)

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 15.2 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,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 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 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 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The accident analysis requires five MSSVs per steam generator be OPERABLE to provide overpressure protection for design basis transients occurring at 100.37% 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 System 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 table is 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 MTC 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 described in the attachment to Reference 5, with an appropriate allowance for calorimetric power uncertainty.

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 MTC is positive the reactor power may increase as a result of an RCS heatup event such that flow capacity of the

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 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 in resetting 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.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to Reference 5, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

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 Protection 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

SRs are specified in the Inservice Testing Program. MSSVs 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 SR. The MSSV lift settings given in the LCO are for operability, however, the valves are reset to ±1% during the surveillance to allow for drift.

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.

REFERENCES

1. UFSAR, Section 10.3.1.

2. ASME, Boiler and Pressure Vessel Code, Section III.

3. UFSAR, Section 15.2.

4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

5. NRC Information Notice 94-60, "Potential Overpressurization of the Main Steam System," August 22, 1994.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Trip Valves (MSTVs)

BASES

BACKGROUND

The MSTVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSTV closure terminates flow from the unaffected (intact) steam generators.

One MSTV is located in each main steam line outside, but close to, containment. The MSTVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSTV closure. Closing the MSTVs isolates each steam generator from the others, and isolates the turbine, Steam Dump System, and other auxiliary steam supplies from the steam generators.

The MSTVs close on a main steam isolation signal generated by either intermediate high high containment pressure, high steam flow coincident with low low RCS T_{avg}, or low steam line pressure. The MSTVs fail closed on loss of control air pressure.

Each MSTV has an MSTV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSTVs. The MSTV bypass valves may also be actuated manually.

A description of the MSTVs is found in the UFSAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSTVs is established by the containment analysis for the main steam line break (MSLB) inside containment, discussed in the UFSAR, Section 6.2 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the UFSAR, Section 15.4.2 (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 MSTV to close on demand).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting case for the containment analysis is the MSLB inside containment, with a loss of offsite power following turbine trip, and failure of the Non Return Valve (NRV) on the affected steam generator to close. At lower powers, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to reverse flow and failure of the NRV to close, the additional mass and energy in the steam headers downstream from the other MSTVs 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 MSLB events against different acceptance criteria. The MSLB outside containment upstream of the MSTV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The MSLB inside containment at hot zero power is the limiting case for a post trip return to power. 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 MSTV to close.

The MSTVs only serve a safety function and remain open during power operation. These valves operate under the following situations:

a. A HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the NRV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSTVs close. After MSTV 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 MSTVs in the unaffected loops. Closure of the MSTVs isolates the break from the unaffected steam generators.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	b. A break outside of containment and upstream from the MSTV 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 MSTVs isolates the break and limits the blowdown to a single steam generator. c. A break downstream of the MSTVs will be isolated by the closure of the MSTVs. d. Following a steam generator tube rupture, the operator will isolate flow to the ruptured steam generator, adjust auxiliary feedwater flow to maintain specified water levels in the ruptured and intact steam generators and manually isolate steam flow from the ruptured generator to the turbine-driven auxiliary feedwater in the Main Steam Valve House. The operator will also verify that the steam generator power operated relief valves are available and their manual isolation valves are opened (if required) in preparation for subsequent steps. Closure of the MSTVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases. e. The MSTVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSTV OPERABILITY is concerned. The MSTVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that three MSTVs in the steam lines be OPERABLE. The MSTVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal. This LCO provides assurance that the MSTVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 50.67 (Ref. 4) limits or the NRC staff approved licensing basis.

BASES

APPLICABILITY

The MSTVs 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 MSTVs are closed, they are already performing the safety function.

In MODE 4, the steam generator energy is low and the MSTVs are not required to support the safety analyses 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 MSTVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

With one MSTV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSTV 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 MSTVs.

The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSTVs 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 MSTV 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 MSTVs 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 MSTV.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Since the MSTVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSTVs may either be restored to OPERABLE status or closed. When closed, the MSTVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition A.

For inoperable MSTVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSTVs 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 MSTV 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 MSTVs 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 MSTV isolation time is ≤ 5.0 seconds. The MSTV isolation time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MSTVs should not be tested at power, since even a part stroke exercise increases the risk of a valve closure when the unit is generating power. As the MSTVs are not tested at power, they are exempt from the ASME Code (Ref. 5) requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1 (continued)

This test may 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. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

SR 3.7.2.2

This SR verifies that each MSTV closes on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.3.
2. UFSAR, Section 6.2.
3. UFSAR, Section 15.4.2.
4. 10 CFR 50.67.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs), Main Feedwater Pump Discharge Valves (MFPDVs), Main Feedwater Regulating Valves (MFRVs), and Main Feedwater Regulating Bypass Valves (MFRBVs)

BASES

BACKGROUND

The MFIV and the MFRV are in series in the Main Feedwater (MFW) line upstream of each steam generator. The MFRBV is parallel to both the MFIV and the MFRV. The MFPDV is located at the discharge of each main feedwater pump. The valves are located outside of the containment. These valves provide the isolation of each MFW line by the closure of the MFIV and MFRBV, the MFRV and MFRBV, or the closure of the MFPDV. To provide the needed isolation given the single failure of one of the valves, all four valve types are required to be OPERABLE. The MFIVs and the MFRVs provide single failure protection for each other in one flow path and the MFPDVs and the MFRBVs provide single failure protection for each other in the other flow path.

The safety-related function of the MFIVs, MFPDVs, MFRVs and the MFRBVs is to provide isolation of MFW from the secondary side of the steam generators following a high energy line break. Closure of the MFIV and MFRBV, the MFRV and MFRBV, or the closure of the MFPDV terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam or feedwater line breaks and minimizing the positive reactivity effects of the Reactor Coolant System (RCS) cooldown associated with the blowdown. In the event of pipe rupture inside the containment, the valves limit the quantity of high energy fluid that enters the containment through the broken loop.

The containment isolation MFW check valve in each loop provides the first pressure boundary for the addition of Auxiliary Feedwater (AFW) to the intact loops and prevents back flow in the feedwater line should a break occur upstream of these valves. These check valves also isolate the non-safety-related portion of the MFW system from the safety-related portion of the system. The piping volume from the feedwater isolation valve to the steam generators is considered in calculating mass and energy release following either a steam or feedwater line break.

(continued)

BASES

BACKGROUND (continued)

The MFIVs, MFPDVs, MFRVs, and MFRBVs close on receipt of Safety Injection or Steam Generator Water Level—High High signal. The MFIVs, MFPDVs, MFRVs, and MFRBVs may also be actuated manually.

A description of the operation of the MFIVs, MFPDVs, MFRVs, and MFRBVs is found in the UFSAR, Section 10.4.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis for the closure of the MFIVs, MFPDVs, MFRVs, and MFRBVs is established by the analyses for the Main Steam Line Break (MSLB). It is also influenced by the accident analysis for the Feedwater Line Break (FWLB). Closure of the MFIVs and MFRBVs, or MFRVs and MFRBVs, or the MFPDVs, may also be relied on to terminate an MSLB on receipt of an SI signal for core response analysis and for an excess feedwater event upon the receipt of a Steam Generator Water Level—High High signal.

Failure of an MFIV and MFRV, or an MFRBV and MFPDV to close following an MSLB or FWLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an MSLB or FWLB event.

The MFIVs, MFPDVs, MFRVs, and MFRBVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that the MFIVs, MFPDVs, MFRVs, and MFRBVs will isolate MFW flow to the steam generators, following an FWLB or MSLB.

This LCO requires that three MFIVs, three MFPDVs, three MFRVs, and three MFRBVs be OPERABLE. The valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal. The MFIVs and the MFRVs provide single failure protection for each other, and the MFPDV and the MFRBV provide single failure protection for each other.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an MSLB or FWLB inside containment. A feedwater isolation signal on high high steam generator level is relied on to terminate an excess feedwater flow event, and failure to meet the LCO may result in the introduction of water into the main steam lines.

(continued)

BASES

APPLICABILITY

The MFIVs, MFPDVs, MFRVs, and MFRBVs must be OPERABLE whenever there is significant mass and energy in the RCS and steam generators. In MODES 1, 2, and 3, the MFIVs, MFPDVs, MFRVs, and MFRBVs 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, MFPDVs, MFRVs, and MFRBVs are not required to be OPERABLE.

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 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.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 other administrative controls to ensure that the valves are closed or isolated.

C.1 and C.2

With one MFRBV 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 MFRBVs 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 other administrative controls to ensure that these valves are closed or isolated.

D.1 and D.2

With one MFPDV 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.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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 MFPDVs 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, and in view of other administrative controls, to ensure that these valves are closed or isolated.

E.1

With two inoperable valves in the same flow path, there may be no redundant system to operate automatically and perform the required safety function. For example, either a MFIV and a MFRV in the same main feedwater line are inoperable or a MFPDV and a MFRBV are inoperable. Under these conditions, at least one of the affected valves 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 affected valves, or otherwise isolate the affected flow path.

F.1 and F.2

If the inoperable 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 isolation time of each MFIV, MFRV, and MFRBV is ≤ 6.98 seconds and the isolation time for each MFPDV is ≤ 60 seconds. The isolation times are assumed in the accident and containment analyses. This Surveillance is normally performed during a refueling outage.

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, MFRBV, and MFPDV can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.4.3.

B 3.7 PLANT SYSTEMS

B 3.7.4 Steam Generator Power Operated Relief Valves (SG PORVs)

BASES

BACKGROUND	The SG PORVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the condenser dump valves not be available, as discussed in the UFSAR, Section 10.3 (Ref. 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the emergency condensate storage tank (ECST) (or, alternately, with main feedwater from the condenser hotwell or main condensate tanks, if available). One SG PORV line for each of the three steam generators is provided. Each SG PORV line consists of one SG PORV and an associated upstream manual isolation valve. The SG PORVs are provided with upstream manual isolation valves to permit their being tested at power, and to provide an alternate means of isolation. The SG PORVs are equipped with pneumatic controllers to permit control of the cooldown rate. The SG PORVs are provided with a backup supply tank which is pressurized from the instrument air header via a check valve arrangement that, on a loss of pressure in the normal instrument air supply, automatically supplies air to operate the SG PORVs. The air supply is sized to provide the sufficient pressurized air to operate the SG PORVs until manual operation of the SG PORVs can be established. A description of the SG PORVs is found in Reference 1. The SG PORVs are OPERABLE when they are capable of providing controlled relief of the main steam flow and capable of being fully opened and closed, either remotely or by local manual operation.
APPLICABLE SAFETY ANALYSES	The design basis of the SG PORVs is established by the capability to cool the unit to RHR entry conditions. The SG PORVs are used in conjunction with auxiliary feedwater supplied from the ECST (or, alternately, with main feedwater from the condenser hotwell or main condensate tanks, if

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

available). Adequate inventory is available in the ECST to support operation for 2 hours in MODE 3 followed by a 4 hour cooldown to the RHR entry conditions.

In the SGTR accident analysis presented in Reference 2, the SG PORVs are assumed to be used by the operator to cool down the unit to RHR entry conditions when the SGTR is accompanied by a loss of offsite power, which renders the condenser dump valves unavailable. Prior to operator actions to cool down the unit, the SG PORVs and main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event. Thus, the SGTR is the limiting event for the SG PORVs. The requirement for three SG PORVs to be OPERABLE satisfies the SGTR accident analysis requirements, including consideration of a single failure of one SG PORV to open on demand.

The SG PORVs are equipped with manual isolation valves in the event an SG PORV spuriously fails open or fails to close during use.

The SG PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Three SG PORV lines are required to be OPERABLE. One SG PORV line is required from each of three steam generators to ensure that at least one SG PORV line is available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a single, active failure of a second SG PORV line on an unaffected steam generator. The manual isolation valves must be OPERABLE to isolate a failed open SG PORV line. A closed manual isolation valve does not render it or its SG PORV line inoperable because operator action time to open the manual isolation valve is supported in the accident analysis.

(continued)

BASES

LCO (continued)

Failure to meet the LCO can result in the inability to cool the unit to RHR entry conditions following an event in which the condenser is unavailable for use with the Steam Dump System.

An SG PORV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing, remotely or by local manual operation on demand.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when a steam generator is being relied upon for heat removal, the SG PORVs are required to be OPERABLE.

In MODE 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one required SG PORV 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 SG PORV lines, a nonsafety grade backup in the Steam Dump System, and MSSVs.

B.1

With two or more SG PORV lines inoperable, action must be taken to restore all but one SG PORV line to OPERABLE status. Since the upstream manual isolation valve can be closed to isolate an SG PORV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable SG PORV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the SG PORV lines.

C.1 and C.2

If the SG PORV 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. The allowed Completion Times are reasonable, based on operating

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 SG PORVs must be able to be opened either remotely or locally and throttled through their full range. This SR ensures that the SG PORVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an SG PORV during a unit cooldown may satisfy this requirement. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.4.2

The function of the upstream manual isolation valve is to isolate a failed SG PORV. Cycling the upstream manual isolation valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the upstream manual isolation valve during unit cooldown may satisfy this requirement. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.3.
2. UFSAR, Section 15.4.3.

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 to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction through separate and independent suction lines from the emergency condensate storage tank (ECST) (LCO 3.7.6) and pump to the steam generator secondary side via separate and independent connections to the main feedwater (MFW) piping outside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or steam generator power operated relief valves (SG PORVs) (LCO 3.7.4). If the main condenser is available, steam may be released via the steam dump valves and recirculated to the condenser hotwell.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. Each pump is aligned to one steam generator, and the capacity of each pump is sufficient to provide the designated flow assumed in the accident analysis. The pumps are equipped with 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 normally feeds one steam generator, although each pump has the capability to be realigned to feed other steam generators. The steam turbine driven AFW pump receives steam from three main steam lines upstream of the main steam trip valves (MSTVs). The steam supply lines combine into a header which is isolated from the steam driven auxiliary feedwater pump by two parallel valves. Main steam trip valves, MS-TV-111A and MS-TV-111B (Unit 1), MS-TV-211A and MS-TV-211B (Unit 2) are powered from separate 125 V DC trains and actuated by the Engineered Safety Features Actuation System (ESFAS). Opening of either trip valve will provide sufficient steam to the steam driven pump to produce the design flow rate from the ECST to the steam generator(s).

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

(continued)

BASES

BACKGROUND (continued)	The AFW pumps may be aligned and supply a common header capable of feeding all steam generators. 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 steam generator(s) to remove decay heat with steam generator pressure associated with the lowest setpoint MSSV. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the SG PORVs. The AFW System actuates automatically on Steam Generator Water Level low-low by the ESFAS (LCO 3.3.2). The system also actuates on loss of offsite power, safety injection, and trip of all MFW pumps. The AFW System is discussed in the UFSAR, Section 10.4.3.2 (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 steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus 3%. In addition, the AFW System must supply enough makeup water to replace steam generator 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 Accidents (DBAs) and transients for the AFW System are as follows: a. Feedwater Line Break (FWLB); b. Main Steam Line Break (MSLB); and c. Loss of MFW.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In addition, the minimum available AFW flow and system characteristics are considerations in the analysis of a small break loss of coolant accident (LOCA).

The AFW System design is such that it can perform its function following an FWLB between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of the steam turbine driven AFW pump. In such a case, the ESFAS logic may not detect the affected steam generator if the backflow check valve to the affected MFW header worked properly. One motor driven AFW pump would deliver to the broken MFW header at maximum design flow until the problem was detected, and flow terminated by the operator. Sufficient flow would be delivered to the intact steam generator by the redundant AFW pump.

The ESFAS automatically actuates the AFW turbine driven pump when required to ensure an adequate feedwater supply to its dedicated steam generator during loss of power. Air or motor operated valves are provided for each AFW line to control the AFW flow to each steam generator.

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 independent AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of AFW 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 MSTVs.

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. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to separate steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant

(continued)

BASES

LCO (continued)

steam supplies from each of two main steam supply paths through MS-TV-111A and MS-TV-111B (Unit 1), MS-TV-211A and MS-TV-211B (Unit 2), which receive steam from at least two of the three main steam lines upstream of the MSTVs. The piping, valves, instrumentation, and controls required to perform the safety function in the required flow paths also are required to be OPERABLE.

In addition, if a seismic air tank or the inlet check valve to the seismic air tank associated with any of the air operated valves (FW-PCV-159A, FW-PCV-159B, FW-HCV-100A, FW-HCV-100B, FW-HCV-100C, MS-TV-111A and MS-TV-111B (Unit 1), FW-PCV-259A, FW-PCV-259B, FW-HCV-200A, FW-HCV-200B, FW-HCV-200C, MS-TV-211A and MS-TV-211B (Unit 2)) is removed from service, or becomes unavailable, then the associated valve is considered inoperable.

The LCO is modified by a Note indicating that one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4 when the steam generator is relied upon for heat removal. 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 one AFW train is required to be OPERABLE when the steam generator(s) is relied upon for heat removal.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

A.1

If one of the two steam supplies, MS-TV-111A and MS-TV-111B (Unit 1), MS-TV-211A and MS-TV-211B (Unit 2), to the turbine driven AFW train is inoperable or if a turbine driven AFW pump is inoperable while in MODE 3 immediately following refueling, action must be taken to restore the affected

(continued)

BASES

ACTIONS

A.1 (continued)

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 a steam supply to the turbine driven AFW pump, the 7 day Completion Time is reasonable since there is a redundant steam supply line for the turbine driven pump.

b. For the inoperability of a turbine driven AFW pump while in MODE 3 immediately subsequent to a refueling outage, the 7 day Completion Time is reasonable due to the minimal decay heat levels in this situation.

c. For both the inoperability of a steam supply line to the turbine driven pump 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 during any contiguous 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 Conditions to when the unit has not entered MODE 2 following a refueling. Condition A allows the turbine driven 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.

BASES

ACTIONS (continued)

B.1

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 restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. 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.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any contiguous 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

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains 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, when the steam generator is relied upon for heat removal, 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. Although not required, the unit may continue to cool down and initiate RHR.

BASES

ACTIONS (continued)

D.1

If all three AFW trains 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 perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.
Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions required by the Technical Specifications are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

E.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 the required AFW train inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status. The immediate Completion Time is consistent with LCO 3.4.6.

SURVEILLANCE REQUIREMENTS

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. 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 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref 2). Because it is sometimes undesirable to introduce cold AFW into the steam generators while they are operating, this testing is typically performed on recirculation 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. Performance of inservice testing discussed in the ASME Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there may be insufficient steam pressure to perform the test.

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the SR is not required in MODE 4. In MODE 4, the heat removal requirements would be less providing more time for operator action to manually align the required valves.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that 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 function is not required. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there may be insufficient steam pressure to perform the test. Note 2 states that the SR is not required in MODE 4. In MODE 4, the heat removal requirements would be less providing more time for operator action to manually start the required AFW pump.

SR 3.7.5.5

This SR verifies that the AFW is properly aligned by verifying the flow paths from the ECST to each steam generator prior to entering MODE 3 after more than 30 contiguous days in any combination of MODES 5, 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 that 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 that the flow path from the ECST to the steam generators is properly aligned.

REFERENCES

1. UFSAR, Section 10.4.3.2.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

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B 3.7 PLANT SYSTEMS

B 3.7.6 Emergency Condensate Storage Tank (ECST)

BASES

BACKGROUND	The ECST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The ECST 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 (MSSVs) or the steam generator power operated relief valves (SG PORVs). The AFW pumps operate with a continuous recirculation to the ECST. When the main steam trip valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam dump valves. The condensed steam is returned to the hotwell and is pumped to the 300,000 gallon condensate storage tank which can be aligned to gravity feed the ECST. This has the advantage of conserving condensate while minimizing releases to the environment. Because the ECST 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 ECST is designed to Seismic Category I to ensure availability of the feedwater supply. Feedwater is also available from alternate sources. A description of the ECST is found in the UFSAR, Section 9.2.4 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The ECST provides cooling water to remove decay heat and to cool down the unit following all events in the accident analysis as discussed in the UFSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the analysis assumption is 2 hours in MODE 3, steaming through the MSSVs, followed by a 4 hour cooldown to residual heat removal (RHR) entry conditions at the design cooldown rate.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting event for the condensate volume is the large feedwater line break coincident with a loss of offsite power. Single failures accommodated by the accident include the following:

a. Failure of the diesel generator powering the motor driven AFW pump to one unaffected steam generator (requiring additional steam to drive the remaining AFW pump turbine); and

b. Failure of the steam driven AFW pump (requiring a longer time for cooldown using only one motor driven AFW pump).

These are not usually the limiting failures in terms of consequences for these events.

A nonlimiting event considered in ECST inventory determinations is a break in either the main feedwater or AFW line near where the two join. This break has the potential for dumping condensate until terminated by operator action, since the Engineered Safety Features Actuation System (LCO 3.3.2, ESFAS) starts the AFW system and would not detect a difference in pressure between the steam generators for this break location. This loss of condensate inventory is partially compensated for by the retention of steam generator inventory.

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

LCO

To satisfy accident analysis assumptions, the ECST must contain sufficient cooling water to remove decay heat for 30 minutes following a reactor trip from 100.37% RTP, and then to cool down the RCS to RHR entry conditions, assuming a coincident loss of offsite power and the most adverse single failure. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooldown, as well as account for any losses from the steam driven AFW pump turbine, or before isolating AFW to a broken line.

The ECST level required is equivalent to a contained volume of ≥ 110,000 gallons, which is based on holding the unit in MODE 3 for 8 hours, or maintaining the unit in MODE 3 for 2 hours followed by a 4 hour cooldown to RHR entry

(continued)

BASES

LCO (continued)

conditions within the limit of 100°F/hour. The basis for these times is established in the accident analysis.

The OPERABILITY of the ECST is determined by maintaining the tank level at or above the minimum required level to ensure the minimum volume of water.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the ECST is required to be OPERABLE.

In MODE 5 or 6, the ECST is not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the ECST is not OPERABLE, the OPERABILITY of the backup supply, the Condensate Storage Tank, should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup feedwater supply must include verification that the flow paths from the backup water supply to the AFW pumps are OPERABLE, and that the backup supply has the required volume of water available. The ECST 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 ECST.

B.1 and B.2

If the ECST 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 that the ECST contains the required volume of cooling water. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.4.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.7 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 1 gpm tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 1.0 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours).

If the main steam safety valves (MSSVs) open for 2 hours following a trip from full power with the specified activity limit, the resultant 2 hour dose to a person at the exclusion area boundary (EAB) would be less than 0.033 rem TEDE (the consequences of the design basis main steam line break accident).

Operating a unit at the allowable limits could result in a 2 hour EAB exposure at the Regulatory Guide 1.183 (Ref. 1) limits, or the limits established as the NRC staff approved licensing basis.

BASES

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the UFSAR, Chapter 15 (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 limits specified in Regulatory Guide 1.183 (Ref. 1).

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs and steam generator power operated relief valves (SG PORVs). 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 SG PORV 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 ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to the required limit (Ref. 1).

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.

BASES

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 steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

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 cannot be restored to within limits 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Regulatory Guide 1.183, July 2000.

2. UFSAR, Chapter 15.

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B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water (SW) System

BASES

BACKGROUND

The SW System 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 SW System also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SW System is common to Units 1 and 2 and is designed for the simultaneous operation of various subsystems and components of both units. The source of cooling water for the SW System is the Service Water Reservoir. The SW System consists of two loops and components can be aligned to operate on either loop. There are four main SW pumps taking suction on the Service Water Reservoir, supplying various components through the supply headers, and then returning to the Service Water Reservoir through the return headers. Eight spray arrays are available to provide cooling to the service water, as well as two winter bypass lines. The isolation valves on the spray array lines automatically open, and the isolation valves on the winter bypass lines automatically shut, following receipt of a Safety Injection signal. The main SW pumps are powered from the four emergency buses (two from each unit). There are also two auxiliary SW pumps which take suction on North Anna Reservoir and discharge to the supply header. When the auxiliary SW pumps are in service, the return header may be redirected to waste heat treatment facility if desired. However, the auxiliary SW pumps are strictly a backup to the normal arrangement and are not credited in the analysis for a DBA.

During a design basis loss of coolant accident (LOCA) concurrent with a loss of offsite power to both units, one SW loop will provide sufficient cooling to supply post-LOCA loads on one unit and shutdown and cooldown loads on the other unit. During a DBA, the two SW loops are cross-connected at the recirculation spray (RS) heat exchanger supply and return headers of the accident unit. On a Safety Injection (SI) signal on either unit, all four main SW pumps start and the system is aligned for Service Water Reservoir spray operation. On a containment high-high

(continued)

BASES

BACKGROUND (continued)

pressure signal the accident unit's Component Cooling (CC) heat exchangers are isolated from the SW System and its RS heat exchangers are placed into service. All safety-related systems or components requiring cooling during an accident are cooled by the SW System, including the RS heat exchangers, main control room air conditioning condensers, and charging pump lubricating oil and gearbox coolers.

The SW System also provides cooling to the instrument air compressors, which are not safety-related, and the non-accident unit's CC heat exchangers, and serves as a backup water supply to the Auxiliary Feedwater System, the spent fuel pool coolers, and the containment recirculation air cooling coils. The SW System has sufficient redundancy to withstand a single failure, including the failure of an emergency diesel generator on the affected unit.

Additional information about the design and operation of the SW System, along with a list of the components served, is presented in the UFSAR, Section 9.2.1 (Ref. 1). The principal safety related function of the SW System is the removal of decay heat from the reactor following a DBA via the RS System.

APPLICABLE SAFETY ANALYSES

The design basis of the SW System is for one SW loop, in conjunction with the RS System, to remove core decay heat following a design basis LOCA as discussed in the UFSAR, Section 6.2.2 (Ref. 2). This prevents the containment sump fluid from increasing in temperature, once the cooler RWST water has reached equilibrium with the fluid in containment, during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid which is supplied to the Reactor Coolant System by the ECCS pumps. The SW System also prevents the buildup of containment pressure from exceeding the containment design pressure by removing heat through the RS System heat exchangers. The SW System is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The SW System, in conjunction with the CC System, also cools the unit from residual heat removal (RHR), as discussed in the UFSAR, Section 5.5.4, (Ref. 3) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CC and RHR System trains that are operating.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

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

A SW loop is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. Either

a.1 Two SW pumps are OPERABLE in an OPERABLE flow path; or

a.2 One SW pump is OPERABLE in an OPERABLE flow path provided two SW pumps are OPERABLE in the other loop and SW flow to the CC heat exchangers is throttled; and

b. Either

b.1 Three spray arrays are OPERABLE in an OPERABLE flow path; or

b.2 Two spray arrays are OPERABLE in an OPERABLE flow path, and the spray valves for the required OPERABLE spray arrays are secured in the accident position and power removed from the valve operators; and

c. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

A required valve directing flow to a spray array, bypass line, or other component is considered OPERABLE if it is capable of automatically moving to its safety position or if it is administratively placed in its safety position.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the SW System is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SW System and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SW System are determined by the systems it supports.

ACTIONS

A.1

If one SW System loop is inoperable due to an inoperable SW pump, the flow resistance of the system must be adjusted within 72 hours by throttling component cooling water heat exchanger flows to ensure that design flows to the RS System heat exchangers are achieved following an accident. The required resistance is obtained by throttling SW flow through the CC heat exchangers. In this configuration, a single failure disabling a SW pump would not result in loss of the SW System function.

B.1 and B.2

If one or more SW System loops are inoperable due to only two SW pumps being OPERABLE, the flow resistance of the system must be adjusted within one hour to ensure that design flows to the RS System heat exchangers are achieved if no additional failures occur following an accident. The required resistance is obtained by throttling SW flow through the CC heat exchangers. Two SW pumps aligned to one loop or one SW pump aligned to each loop is capable of performing the safety function if CC heat exchanger flow is properly throttled. However, overall reliability is reduced because a single failure disabling a SW pump could result in loss of the SW System function. The one hour time reflects the need to minimize the time that two pumps are inoperable and CC heat exchanger flow is not properly throttled, but is a reasonable time based on the low probability of a DBA occurring during this time period. Restoring one SW pump to OPERABLE status within 72 hours together with the throttling ensures that design flows to the RS System heat exchangers are achieved following an accident. The required resistance is obtained by throttling SW flow through the CC heat exchangers. In this configuration, a single failure disabling a SW pump would not result in loss of the SW System function.

BASES

ACTIONS (continued)

C.1

If one SW loop is inoperable for reasons other than Condition A, action must be taken to restore the loop to OPERABLE status.

In this Condition, the remaining OPERABLE SW loop is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SW loop could result in loss of SW System function. The inoperable SW loop is required to be restored to OPERABLE status within 72 hours unless the criteria for a 7 day Completion Time are met, as stated in the 72 hour Completion Time Note. The 7 day Completion Time applies if the three criteria in the 7 day Completion Time Note are met.

The first criterion in the 7 day Completion Time Note states that the 7 day Completion Time is only applicable if the inoperability of one SW loop is part of SW System upgrades. Service Water System upgrades include modification and maintenance activities associated with the installation of new discharge headers and spray arrays, mechanical and chemical cleaning of SW System piping and valves, pipe repair and replacement, valve repair and replacement, installation of corrosion mitigation measures and inspection of and repairs to buried piping interior coatings and pump or valve house components. The second criterion in the 7 day Completion Time Note states that the 7 day Completion Time is only applicable if three SW pumps are OPERABLE from initial Condition entry, including one SW pump being allowed to not have automatic start capability. The third criterion in the 7 day Completion Time Note states that the 7 day Completion Time is only applicable if two auxiliary SW pumps are OPERABLE from initial Condition entry. The 72 hour and 7 day Completion Times are both based on the redundant capabilities afforded by the OPERABLE loop, and the low probability of a DBA occurring during this time period. The 7 day Completion Time also credits the redundant capabilities afforded by three OPERABLE SW pumps (one without automatic start capability) and two OPERABLE auxiliary SW pumps. Changing the designation of the three OPERABLE SW pumps during the 7 day Completion Time is allowed.

BASES

ACTIONS (continued)

D.1 and D.2

If the SW pumps or loop 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.

E.1 and E.2

If two SW loops are inoperable for reasons other than only two SW pumps being OPERABLE, the SW System cannot perform the safety function. With two SW loops inoperable, the CC System and, consequently, the Residual Heat Removal (RHR) System have no heat sink and are inoperable. Twelve hours is allowed to enter MODE 4, in which the Steam Generators can be used for decay heat removal to maintain reactor temperature. Twelve hours is reasonable, based on operating experience, to reach MODE 4 from full power conditions in an orderly manner and without challenging unit systems. The unit may then remain in MODE 4 until a method to further cool the units becomes available, but actions to determine a method and cool the unit to a condition outside of the Applicability must be initiated within one hour and continued in a reasonable manner and without delay until the unit is brought to MODE 5.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the SW System components or systems may render those components inoperable, but does not affect the OPERABILITY of the SW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the SW System flow path provides assurance that the proper flow paths exist for SW System 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1 (continued)

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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.2

This SR verifies proper automatic operation of the SW System valves on an actual or simulated actuation signal. The SW System 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.3

This SR verifies proper automatic operation of the SW pumps on an actual or simulated actuation signal. The SW System is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.1.

2. UFSAR, Section 6.2.2.

3. UFSAR, Section 5.5.4.

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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 (SW) System.

The ultimate heat sink is the Service Water Reservoir and its associated retaining structures, and is the normal source of service water for Units 1 and 2.

The Service Water Reservoir is located approximately 500 ft. south of the station site area. The Service Water Reservoir is adequate to provide sufficient cooling to permit simultaneous safe shutdown and cooldown of both units, and then maintain them in a safe-shutdown condition. Further, in the event of a design basis loss of coolant accident (LOCA) in one unit concurrent with a loss of offsite power to both units, the Service Water Reservoir is designed to provide sufficient water inventory to supply post-LOCA loads on one unit and shutdown and cooldown loads on the other unit and maintain them in a safe-shutdown condition for at least 30 days without makeup. After 30 days, makeup to the Service Water Reservoir is provided from the North Anna Reservoir as necessary to maintain cooling water inventory, ensuring a continued cooling capability. The Service Water Reservoir spray system is designed for operation of two units based on the occurrence of a LOCA on one unit with cooldown of the non-accident unit and simultaneous loss of offsite power to both units.

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 North Anna Reservoir provides a backup source of service water using the auxiliary SW pumps, and can provide makeup water to the Service Water Reservoir using the Circulating Water screen wash pumps, but is not credited for the DBA. The Lake Anna Dam impounds a lake with a surface area of 13,000 acres and 305,000 acre-ft. of storage, at its normal-stage elevation of 250 ft., along the channel of the North Anna River. The lake is normally used by the power station as

(continued)

BASES

BACKGROUND (continued)

a cooling pond for condenser circulating water. To improve the thermal performance of the lake, it has been divided by a series of dikes and canals into two parts. The larger, referred to as the North Anna Reservoir, is 9600 acres. The smaller part, called the waste heat treatment facility, is 3400 acres. When the North Anna Reservoir is used by the SW System, water is withdrawn from the North Anna Reservoir and discharged to the waste heat treatment facility, though it is possible to discharge water to the Service Water Reservoir.

The two sources of water are independent, and each has separate, redundant supply and discharge headers. The only common points are the main redundant supply and discharge headers in the service building where distribution to the components takes place. These common headers are encased in concrete.

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. Its maximum post accident heat load occurs in the first hour after a design basis LOCA. During this time, the Recirculation Spray (RS) subsystems have started to remove the core decay heat.

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. The analyses provide the details of the assumptions used in the analysis, which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and the worst case single active failure (e.g., single failure of an EDG). The UHS is designed in accordance with the Regulatory Guide 1.27 (Ref. 2) requirement for 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. The UHS is considered OPERABLE if it contains a sufficient volume of water at or below the maximum temperature that would allow the SW System 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 SW System. To meet this condition, the Service Water Reservoir temperature should not exceed 95°F and the level should not fall below 313 ft mean sea level 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 the UHS is inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 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 that adequate long term (30 day) cooling can be maintained. The specified level also ensures that sufficient NPSH is available to operate the SW pumps. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2

This SR verifies that the SW System is available with the maximum accident or normal design heat loads for 30 days following a Design Basis Accident. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.

2. Regulatory Guide 1.27, March, 1974.

B 3.7 PLANT SYSTEMS

B 3.7.10 Main Control Room/Emergency Switchgear Room (MCR/ESGR) Emergency Ventilation System (EVS)

BASES

BACKGROUND

The MCR/ESGR Emergency Ventilation System (EVS) provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. The MCR/ESGR EVS consists of four 100% capacity redundant trains (2 per unit) that can filter and recirculate air inside the MCR/ESGR envelope or supply filtered makeup air to the MCR/ESGR envelope, and a MCR/ESGR boundary that limits the inleakage of unfiltered air. Each train consists of a heater, demister filter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan (Ref. 1). Ductwork, valves, dampers, doors, barriers, and instrumentation also form part of the system. One EVS train is capable of performing the safety function of supplying outside filtered air. In the event of a Safety Injection (SI), the two MCR/ESGR EVS trains on the accident unit actuate automatically in recirculation. All available trains of MCR/ESGR EVS start automatically on a fuel building radiation monitor signal or manual actuation of the MCR/ESGR Isolation Actuation Instrumentation. These trains can also be aligned to provide filtered outside air when appropriate. Either train from the other unit can be manually actuated to provide filtered outside air approximately 60 minutes after the event. However, due to the location of the air intake for 1-HV-F-41, it can not be used to satisfy the requirements of LCO 3.7.10. Two of the three remaining trains (1-HV-F-42, 2-HV-F-41, and 2-HV-F-42) are required for independence and redundancy.

The MCR/ESGR envelope is the area within the confines of the MCR/ESGR envelope 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 MCR/ESGR envelope is protected during normal operation, natural

(continued)

BACKGROUND (continued)

events, and accident conditions. The MCR/ESGR envelope boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the MCR/ESGR envelope. The OPERABILITY of the MCR/ESGR envelope boundary must be maintained to ensure that the inleakage of unfiltered air into the MCR/ESGR envelope will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to MCR/ESGR envelope occupants. The MCR/ESGR envelope and its boundary are defined in the MCR/ESGR Envelope Habitability Program.

Upon receipt of an actuating signal(s) (i.e., SI, fuel building radiation monitors or manual), normal air supply to and exhaust from the MCR/ESGR envelope is isolated, and at least two trains of MCR/ESGR EVS receive a signal to actuate to recirculate air in the MCR/ESGR envelope. Approximately 60 minutes after actuation of the MCR/ESGR Isolation Actuation Instrumentation, a single MCR/ESGR EVS train is manually actuated or aligned to provide filtered outside air to the MCR/ESGR envelope through HEPA filters and charcoal adsorbers. The demisters remove any entrained water droplets present, to prevent excessive moisture loading of the HEPA filters and charcoal adsorbers. Continuous operation of each train for at least 10 hours per month, with the heaters on, reduces moisture buildup on the HEPA filters and adsorbers. Both the demister and heater are important to the effectiveness of the HEPA filters and charcoal adsorbers.

Although not assumed in the Analysis of Record, pressurization of the MCR/ESGR envelope minimizes infiltration of unfiltered air through the MCR/ESGR envelope boundary from all the surrounding areas adjacent to the MCR/ESGR envelope boundary.

Redundant MCR/ESGR EVS supply and recirculation trains provide the required filtration of outside air should an excessive pressure drop develop across the other filter train.

(continued)

BASES

BACKGROUND (continued)

The MCR/ESGR EVS is designed in accordance with Seismic Category I requirements. Any of the actuation signal(s) will isolate the MCR/ESGR envelope and start the MCR/ESGR EVS trains for the affected unit in recirculation. Requiring two of the three MCR/ESGR EVS trains provides redundancy, assuring that at least one train is available to be realigned to provide filtered outside air.

The MCR/ESGR EVS is designed to maintain a habitable environment in the MCR/ESGR envelope for 30 days of continuous occupancy after a DBA without exceeding the control room operator dose limits of 10 CFR 50, Appendix A, GDC-19 (Ref. 3) for alternative source terms.

APPLICABLE SAFETY ANALYSES

The MCR/ESGR EVS components are arranged in redundant, safety related ventilation trains. The location of most components and ducting within the MCR/ESGR envelope ensures an adequate supply of filtered air to all areas requiring access. The MCR/ESGR EVS provides airborne radiological protection for the MCR/ESGR envelope occupants, as demonstrated by the MCR/ESGR envelope accident dose analyses for the most limiting DBA (LOCA) fission product release presented in the UFSAR, Chapter 15 (Ref. 2). The accident analysis assumes that at least one train is aligned to provide filtered outside air to the MCR/ESGR envelope approximately 60 minutes after MCR/ESGR envelope isolation, but does not take any credit for automatic start of the trains in the recirculation mode or any filtration of recirculated air. Since the MCR/ESGR EVS train associated with 1-HV-F-41 can not be used to provide filtered outside air (due to the location of its air intake with respect to Vent Stack B), it can not be used to satisfy the requirements of LCO 3.7.10.

The North Anna UFSAR describes potentially hazardous chemicals stored onsite in quantities greater than 100 lb. These include hydrogen, sulfuric acid, sodium hydroxide, hydrazine, ethanolamine, and sodium hypochlorite. Evaluations for accidental release of these chemicals indicate that the worst-case concentrations at the control room intake would be expected to be less than their

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

respective toxicity limit (Refs. 1 and 4). The assessment assumed no action being taken by the control room operator (i.e., normal or emergency supply system remains operating).

In the event of fire/smoke external to the MCR/ESGR envelope, equipment and procedures are available to maintain habitability of the control room. Smoke detectors are installed in the return ducts to the MCR Air-Handling Units (AHUs), in the near vicinity of the ESGR AHUs, and in the MCR/ESGR EVS supply ducts, as well as other numerous locations in the ESGRs and MCR. Smoke detectors are also installed in the MCR/ESGR chiller rooms, which are ventilated with air from the Turbine Building, and the Mechanical Equipment rooms. If smoke is detected, the MCR/ESGR normal and EVS supply can be manually isolated. The fire response procedures provide direction for removing smoke from the MCR or ESGRs. (Ref. 5)

The SGTR analysis assumes MCR/ESGR envelope isolation occurs. An unfiltered MCR/ESGR inleakage of 250 cfm is assumed, with filtered makeup air of 900 cfm commencing at 1 hour.

For the remainder of the DBAs, MCR/ESGR envelope isolation is not assumed. Normal ventilation with 500 cfm of additional inleakage is assumed. The safety analysis for a fuel handling accident (FHA) assumes isolation of the MCR/ESGR envelope.

The worst case single active failure of a component of the MCR/ESGR EVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The MCR/ESGR EVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant MCR/ESGR EVS trains are required to be OPERABLE to ensure that at least one train is available to be manually aligned to provide outside filtered air to the MCR/ESGR envelope, if a single active failure disables one of the two required OPERABLE trains. Total system failure, such as from a loss of both required EVS trains or from an inoperable MCR/ESGR envelope boundary, could result in exceeding the control room operator dose limits of 10 CFR 50, Appendix A, GDC-19 (Ref. 3) for alternative source terms, in the event of a large radioactive release.

(continued)

BASES

LCO (continued)

The MCR/ESGR EVS is considered OPERABLE when the individual components necessary to limit MCR/ESGR envelope occupant exposure are OPERABLE in the two required trains of the MCR/ESGR EVS. 1-HV-F-41 can not be used to satisfy the requirements of LCO 3.7.10.

An MCR/ESGR EVS train is OPERABLE when the associated:

a. Fan is OPERABLE;

b. Demister filters, HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Heater, ductwork, valves, and dampers are OPERABLE, and air flow can be maintained.

The MCR/ESGR EVS is shared by Unit 1 and Unit 2.

In order for the MCR/ESGR EVS trains to be considered OPERABLE, the MCR/ESGR envelope boundary must be maintained such that the MCR/ESGR envelope occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that MCR/ESGR envelope occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the MCR/ESGR envelope boundary to be opened intermittently under administrative controls. This Note only applies to openings in the MCR/ESGR envelope boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the MCR/ESGR envelope. This individual will have a method to rapidly close the opening and restore the MCR/ESGR envelope boundary to a condition equivalent to the design condition when a need for MCR/ESGR isolation is indicated.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, MCR/ESGR EVS must be OPERABLE to ensure that the MCR/ESGR envelope will remain habitable during and following a DBA.

The MCR/ESGR EVS must be OPERABLE to respond to the release from a FHA involving recently irradiated fuel assemblies. The MCR/ESGR EVS is only required to be OPERABLE during fuel handling involving recently irradiated fuel assemblies (i.e., fuel assemblies that have occupied part of a critical reactor core within the previous 300 hours) due to radioactive decay.

ACTIONS

A.1

When one required MCR/ESGR EVS train is inoperable, for reasons other than an inoperable MCR/ESGR envelope boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining required OPERABLE MCR/ESGR EVS train is adequate to perform the MCR/ESGR envelope occupant protection function. However, the overall reliability is reduced because a failure in the required OPERABLE EVS trains could result in loss of MCR/ESGR EVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining trains to provide the required capability.

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

If the unfiltered inleakage of potentially contaminated air past the MCR/ESGR envelope boundary and into the MCR/ESGR envelope can result in MCR/ESGR envelope occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem total effective dose equivalent), or inadequate protection of MCR/ESGR envelope occupants from hazardous chemicals or smoke, the MCR/ESGR envelope boundary is inoperable. Actions must be taken to restore an OPERABLE MCR/ESGR envelope boundary within 90 days. During the period that the MCR/ESGR envelope boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on MCR/ESGR envelope 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 MCR/ESGR envelope occupant

(continued)

BASES

ACTIONS

B.1 (continued)

radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that MCR/ESGR envelope occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable MCR/ESGR envelope 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 MCR/ESGR envelope occupants within analyzed limits while limiting the probability that MCR/ESGR envelope 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 MCR/ESGR envelope boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable required MCR/ESGR EVS train or the inoperable MCR/ESGR envelope 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.1.1, D.1.2, and D.2

During movement of recently irradiated fuel, if the inoperable MCR/ESGR EVS train cannot be restored to OPERABLE status within the required Completion Time, the MCR/ESGR envelope must be isolated immediately and the remaining OPERABLE MCR/ESGR train placed in service within one hour. These actions will ensure that the MCR/ESGR envelope is in a configuration that would protect the occupants from radioactive exposure consistent with the DBA assumptions and ensure that any active failures would be readily detected.

ACTIONS

D.1.1, D.1.2, and D.2 (continued)

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

E.1

During movement of recently irradiated fuel assemblies, if a required train of MCR/ESGR EVS train becomes inoperable due to an inoperable MCR/ESGR envelope boundary or two required MCR/ESGR EVS 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. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

F.1

When two required MCR/ESGR EVS trains are inoperable in MODE 1, 2, 3, or 4 for reasons other than an inoperable MCR/ESGR envelope boundary (i.e., Condition B), the MCR/ESGR EVS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 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 the MCR/ESGR EVS are not too severe, testing each required train once every month provides an adequate check of this system. Monthly heater operations dry out any moisture accumulated in the charcoal and HEPA filters from humidity in the ambient air. Each required train must be operated for ≥ 10 continuous hours with the heaters energized. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.2

This SR verifies that the required MCR/ESGR EVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the demister filter, HEPA filter, charcoal adsorber efficiency, minimum and maximum 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

Not Used

SR 3.7.10.4

This SR verifies the OPERABILITY of the MCR/ESGR envelope boundary by testing for unfiltered air inleakage past the MCR/ESGR envelope boundary and into the MCR/ESGR envelope. The details of the testing are specified in the MCR/ESGR Envelope Habitability Program. The MCR/ESGR envelope is considered habitable when the radiological dose to MCR/ESGR envelope occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the MCR/ESGR envelope occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the MCR/ESGR envelope is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the MCR/ESGR envelope boundary to OPERABLE status provided mitigating actions can ensure that the MCR/ESGR envelope 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. 6) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 7). 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. 8). Options for restoring the MCR/ESGR envelope boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the MCR/ESGR envelope boundary, or a combination of these actions.

(continued)

SR 3.7.10.4 (continued)

Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the MCR/ESGR envelope boundary has been restored to OPERABLE status.

REFERENCES

1. UFSAR, Section 6.4.
2. UFSAR, Chapter 15.
3. 10 CFR 50, Appendix A.
4. Control Room Habitability Study (Supplement to 1980 Onsite Control Room Habitability Study - North Anna Power Station Units 1 and 2, January 1982.
5. Letter from L.N. Hartz (Virginia Electric and Power Company) to the USNRC, dated March 3, 2004, Response to Generic Letter 2003-01, "Control Room Habitability - Control Room Testing & Technical Information."
6. Regulatory Guide 1.196.
7. NEI 99-03, "Control Room Habitability Assessment," June 2001.
8. 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 Main Control Room/Emergency Switchgear Room (MCR/ESGR) Air Conditioning System (ACS)

BASES

BACKGROUND

The MCR/ESGR ACS provides cooling for the MCR/ESGR envelope following isolation of the MCR/ESGR envelope. The MCR/ESGR ACS also provides cooling for the MCR/ESGR envelope during routine unit operation.

The MCR/ESGR ACS consists of two independent and redundant subsystems that provide cooling of MCR/ESGR envelope air. Each subsystem consists of two air handling units (one for the MCR and one for the ESGR), one chiller in one subsystem and two chillers in the other, valves, piping, instrumentation, and controls to provide for MCR/ESGR envelope cooling. One subsystem has one chiller, the other has two chillers, either of which can be used by that subsystem, but which are not electrically independent from each other.

The MCR/ESGR ACS is an emergency system, parts of which may also operate during normal unit operations. A single subsystem will provide the required cooling to maintain the MCR/ESGR envelope within design limits. The MCR/ESGR ACS operation in maintaining the MCR/ESGR envelope temperature is discussed in the UFSAR, Section 9.4 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MCR/ESGR ACS is to maintain the MCR/ESGR envelope temperature within limits for 30 days of continuous occupancy after a DBA.

The MCR/ESGR ACS components are arranged in redundant, safety related subsystems. During emergency operation, the MCR/ESGR ACS maintains the temperature within design limits. A single active failure of a component of the MCR/ESGR ACS, with a loss of offsite power, does not impair the ability of the system to perform its design function. The MCR/ESGR ACS is designed in accordance with Seismic Category I requirements. The MCR/ESGR ACS is capable of removing sensible and latent heat loads from the MCR/ESGR envelope, which include consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The MCR/ESGR ACS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant subsystems of the MCR/ESGR ACS, providing cooling to the unit ESGR and associated portion of the MCR, are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

The MCR/ESGR ACS is considered to be OPERABLE when the individual components necessary to cool the MCR/ESGR envelope air are OPERABLE in both required subsystems. Each subsystem consists of two air handling units (one for the MCR and one for the ESGR), one chiller, valves, piping, instrumentation and controls. The two subsystems provide air temperature cooling to the portion of the MCR/ESGR envelope associated with the unit. In addition, an OPERABLE MCR/ESGR ACS must be capable of maintaining air circulation. An MCR/ESGR ACS subsystem does not have to be in operation to be considered OPERABLE. The MCR/ESGR ACS is considered OPERABLE when it is capable of being started by manual actions within 10 minutes. The time of 10 minutes is based on the time required to start the system manually following required testing.

APPLICABILITY

In MODES 1, 2, 3, and 4, and during movement of recently irradiated fuel assemblies, the MCR/ESGR ACS must be OPERABLE to ensure that the MCR/ESGR envelope temperature will not exceed equipment operational requirements following isolation of the MCR/ESGR envelope. The MCR/ESGR ACS is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 300 hours), due to radioactive decay.

ACTIONS

A.1

With one or more required MCR/ESGR ACS subsystem inoperable, and at least 100% of the MCR/ESGR ACS cooling equivalent to a single OPERABLE MCR/ESGR ACS subsystem available, action must be taken to restore OPERABLE status within 30 days. In

(continued)

ACTIONS

A.1 (continued)

this Condition, the remaining OPERABLE MCR/ESGR ACS subsystem is adequate to maintain the MCR/ESGR envelope temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE MCR/ESGR ACS subsystem could result in loss of MCR/ESGR ACS function. The 30 day Completion Time is based on the low probability of an event requiring MCR/ESGR envelope isolation, the consideration that the remaining subsystem can provide the required protection, and that alternate safety or nonsafety related cooling means are available.

The LCO requires the OPERABILITY of a number of independent components. Due to the redundancy of subsystems and the diversity of components, the inoperability of one active component in a subsystem does not render the MCR/ESGR ACS incapable of performing its function. Neither does the inoperability of two different components, each in a different subsystem, necessarily result in a loss of function for the MCR/ESGR ACS (e.g., an inoperable chiller in one subsystem, and an inoperable air handler in the other). This allows increased flexibility in unit operations under circumstances when components in opposite subsystems are inoperable.

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable MCR/ESGR ACS subsystem 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

During movement of recently irradiated fuel, if the required inoperable MCR/ESGR ACS subsystems cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE MCR/ESGR ACS subsystem must be placed in operation immediately. This action ensures that the remaining subsystem is OPERABLE and that active failures will be readily detected.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 MCR/ESGR envelope. 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

During movement of recently irradiated fuel assemblies, with less than 100% of the MCR/ESGR ACS cooling equivalent to a single OPERABLE MCR/ESGR ACS subsystem available, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the MCR/ESGR envelope. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1

With less than 100% of the MCR/ESGR ACS cooling equivalent to a single OPERABLE MCR/ESGR ACS subsystem available in MODE 1, 2, 3, or 4, the MCR/ESGR ACS 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 that the heat removal capability of any one of the three chillers for the unit is sufficient to remove the heat load assumed in the safety analyses in the MCR/ESGR envelope. This SR consists of a combination of testing and calculations. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.4.

B 3.7 PLANT SYSTEMS

B 3.7.12 Emergency Core Cooling System (ECCS) Pump Room Exhaust Air Cleanup System (PREACS)

BASES

BACKGROUND

The ECCS PREACS filters air from the area of the active ECCS components during the recirculation phase of a loss of coolant accident (LOCA). The ECCS PREACS, in conjunction with other normally operating systems, also provides environmental control of temperature in the ECCS pump room areas.

The charging/high head safety injection pump motors have internal fans that provide design cooling requirements without reliance on the central exhaust fans. The associated equipment in the Safeguards Building, Low Head Safety Injection (LHSI) and Outside Recirculation Spray (OSRS) pumps, remain operable for at least 60 minutes without the safeguards exhaust fans in service.

The ECCS PREACS consists of two subsystems, the Safeguards Area Ventilation subsystem and the Auxiliary Building Central Exhaust subsystem. There are two redundant trains in the Safeguards Area Ventilation subsystem. Each train of the Safeguards Area Ventilation subsystem consists of one Safeguards Area exhaust fan, prefilter, and high efficiency particulate air (HEPA) filter and charcoal adsorber assembly for removal of gaseous activity (principally iodines) (shared with the other unit), and controls for the Safeguards Area exhaust filter and bypass dampers. Ductwork, valves or dampers, and instrumentation also form part of the subsystem. The subsystem automatically initiates filtered ventilation of the safeguards pump room following receipt of a Containment Hi-Hi signal from the affected unit.

The Auxiliary Building Central exhaust subsystem consists of the following: three redundant central area exhaust fans (shared with other unit), two redundant filter banks consisting of HEPA filter and charcoal adsorber assembly for removal of gaseous activity (principally iodines) (shared with the other unit), and two redundant trains of controls for the Auxiliary Building Central exhaust subsystem filter

(continued)

BASES

BACKGROUND (continued)

and bypass dampers (shared with the other unit). Ductwork, valves or dampers, and instrumentation also form part of the subsystem. The subsystem initiates filtered ventilation of the charging pump cubicles following manual actuation.

The Auxiliary Building filter banks are shared by the Safeguards Area Ventilation subsystem and the Auxiliary Building Central Exhaust subsystem. Either Auxiliary Building filter bank may be aligned to either ECCS PREACS train. These filter banks are also used by the Auxiliary Building General area exhaust, fuel building exhaust, decontamination building exhaust, and containment purge exhaust.

One Safeguards Area exhaust fan is normally operating and dampers are aligned to bypass the HEPA filters and charcoal adsorbers. During emergency operations, the ECCS PREACS dampers are realigned to begin filtration. Upon receipt of the actuating Engineered Safety Feature Actuation System signal(s), normal air discharges from the Safeguards Area room are diverted through the filter banks. Two Auxiliary Building Central Exhaust fans are normally operating. Air discharges from the Auxiliary Building Central Exhaust area are manually diverted through the filter banks. Required Safeguards Area and Auxiliary Building Central Exhaust area fans are manually actuated if they are not already operating. The prefilters remove any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers.

The ECCS PREACS is discussed in the UFSAR, Section 9.4 (Ref. 1) and it may be used for normal, as well as post accident, atmospheric cleanup functions. The primary purpose of the heaters is to maintain the relative humidity at an acceptable level during normal operations, generally consistent with iodine removal efficiencies per Regulatory Guide 1.52 (Ref. 3). The heaters are not required for post-accident conditions.

APPLICABLE SAFETY ANALYSES

The design basis of the ECCS PREACS is established by the large break LOCA. The system evaluation assumes ECCS leakage outside containment, such as safety injection pump leakage, during the recirculation mode. In such a case, if ECCS leakage exceeds certain levels, the system is required in order to limit radioactive release to within the control room operator dose limits of 10 CFR 50, Appendix A, GDC-19

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

(Ref. 4) for alternative source terms. The analysis of the effects and consequences of a large break LOCA is presented in Reference 2. The ECCS PREACS also may actuate following a small break LOCA, in those cases where the ECCS goes into the recirculation mode of long term cooling, to clean up releases of smaller leaks, such as from valve stem packing. The analyses assume the filtration by the ECCS PREACS does not begin for 60 minutes following an accident.

The ECCS PREACS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two redundant trains of the ECCS PREACS are required to be OPERABLE to ensure that at least one is available. Total system failure could result in elevated temperatures within the Safeguards Area, or in exceeding the control room operator dose limits of 10 CFR 50, Appendix A, GDC-19 (Ref. 4) for alternative source terms.

ECCS PREACS is considered OPERABLE when the individual components necessary to maintain the ECCS pump room ventilation and filtration are OPERABLE in both trains.

An ECCS PREACS train is considered OPERABLE when its associated:

a. Safeguards Area exhaust fan is OPERABLE;

b. One Auxiliary Building HEPA filter and charcoal adsorber assembly (shared with the other unit) is OPERABLE;

c. One Auxiliary Building Central exhaust system fan (shared with other unit) is OPERABLE;

d. HEPA filter and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

e. Ductwork, valves, and dampers are OPERABLE.

Safeguards Area and Auxiliary Building Central exhaust will fail safe to the FILTER position upon loss of power or instrument air. Dampers are considered OPERABLE if capable of moving to the safety position, or if administratively placed in the accident position.

(continued)

BASES

LCO (continued)	Portions of ECCS PREACS may be removed from service (e.g., tag out fans, open ductwork, etc.), in order to perform required testing and maintenance. The system is OPERABLE in this condition if it can be restored to service and perform its function within 60 minutes following an accident. In addition, the required Safeguards Area and charging pump cubicle boundaries for charging pumps not isolated from the Reactor Coolant System must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors, except for those openings which are left open by design, including charging pump ladder wells. The LCO is modified by a Note allowing the ECCS pump room boundary openings not open by design 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 a need for ECCS pump room isolation is indicated.
APPLICABILITY	In MODES 1, 2, 3, and 4, the ECCS PREACS is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS. In MODE 5 or 6, the ECCS PREACS is not required to be OPERABLE since the ECCS is not required to be OPERABLE.
ACTIONS	<u>A.1</u> With one ECCS PREACS train inoperable for reasons other than Condition B (for example, insufficient ventilation exhaust flow rate), action must be taken to restore OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the ECCS PREACS function. The 7 day Completion Time is appropriate because the risk contribution is less than that for the ECCS (72 hour Completion Time), and there are backup ventilation systems for these ECCS pump rooms available to provide cooling as

(continued)

BASES

ACTIONS

A.1 (continued)

needed. The 7 day Completion Time is based on the low probability of a Design Basis Accident (DBA) occurring during this time period, and ability of the remaining train to provide the required capability.

With two ECCS PREACS trains inoperable for reasons other than Condition C or D, LCO 3.0.3 must be entered immediately.

B.1.1, B.1.2, and B.1.3

With one ECCS PREACS train inoperable due to loss of its filtration capability, action must be taken within one hour to determine if the filtration capability is required (Action B.1.1). This is determined based on comparing the most recent ECCS system operational leakage log value against design basis unfiltered leakage assumptions. If the current total ECCS leakage is less than the maximum allowable unfiltered leakage assumed in the design bases, then the filtration capability of ECCS PREACS is not required and an extended period to restore operability can be applied. The value for "maximum allowable unfiltered ECCS leakage" is documented in the UFSAR (reference 6). During this time, both trains remain operable to perform the ventilation exhaust/cooling function. (For example, a problem with the filter itself or its housing affects a single train, and both trains remain operable to perform the ventilation function using either the flow path of the remaining filter or the flow path of the bypass ductwork.)

The action to restore the inoperable train's filtration to operable status within 30 days (Action B.1.3) is reasonable, consistent with:

(a) the dose analysis shows that no filtration function is required when ECCS leakage is less than the maximum allowable unfiltered leakage,

(b) significant margin exists between operating limits and actual dose limits,

(c) the time necessary to complete repairs on the filter assembly and/or associated dampers may be significant, and

(d) the other train of ECCS filtration remains operable to perform its intended safety function if needed.

(continued)

BASES

ACTIONS

B.1.1, B.1.2, and B.1.3 (continued)

In addition, ECCS leakage is required to be monitored by walking down the areas every 12 hours in order to determine whether or not filtration capability is required (Action B.1.2). Establishing monitoring on a 12 hour frequency is based on operating history, which indicated that a sudden change in ECCS leakage is not expected, and the conservatisms in the design basis dose calculations.

B.2

If total ECCS leakage is equal to or greater than the maximum allowable unfiltered leakage limit then the filtration capability of ECCS PREACS is required and actions must be taken to restore Operability of the filter within seven days consistent with an inoperable PREACS train for any other reason.

C.1.1, C.1.2, and C.1.3

If two ECCS PREACS trains are inoperable due to loss of their filtration capability, action must be taken within one hour to determine if the filtration capability is required (Action C.1.1). This is determined based on the Unit's operational ECCS leakage. If the current total ECCS leakage is less than the maximum allowable unfiltered leakage, then the filtration capability of ECCS PREACS is not immediately required and an extended period to restore operability can be applied. During this time, both trains remain operable to perform the ventilation exhaust/cooling function. Both trains of ECCS PREACS may be made inoperable without affecting the ventilation exhaust function by potential problems such as an inoperable bypass damper or a charcoal adsorber issue.

If the filtration capability of ECCS PREACS is not required, actions to restore the filtration function and restore at least one inoperable train to operable status within 14 days (Action C.1.3) are reasonable, consistent with:

(a) the dose analysis shows that no filtration is required when ECCS leakage is less than the maximum allowable unfiltered leakage,

(b) significant margin exists between operating limits and actual dose limits,

(continued)

ACTIONS

C.1.1, C.1.2, and C.1.3 (continued)

(c) operating history indicates that a sudden change in ECCS leakage to greater than the maximum allowable unfiltered leakage is not expected,

(d) the time necessary to complete repairs on the filter assembly and/or associated dampers may be significant, and

(e) unnecessary two-unit shutdown has associated risks.

In addition, ECCS leakage is required to be monitored by walking down the areas every 12 hours in order to determine whether or not filtration capability is required (Action C.1.2). Establishing monitoring on a 12 hour frequency is based on operating history, which indicated that a sudden change in ECCS leakage is not expected, and the conservatisms in the design basis dose calculations.

C.2

If total ECCS leakage is equal to or greater than the maximum allowable unfiltered leakage limit then the filtration capability of ECCS PREACS is required and actions must be taken to restore Operability of at least one train within sixty minutes, consistent with the dose analysis. The analysis assumes the filtration by PREACS does not begin for sixty minutes following an accident (see Applicable Safety Analyses).

D.1.1, D.1.2, and D.1.3

Breaching an ECCS pump room boundary would affect the filtration function of both trains of ECCS PREACS, since the exhaust system may not be able to maintain a negative pressure on the boundary. However, the ventilation/cooling function would not be affected since the charging pump motors have internal fans that provide design cooling requirements without reliance on the central exhaust fans, and the Safeguards Area boundaries are to the exterior atmosphere. Since the inlet to the exhaust ductwork in each pump cubicle in Safeguards is located just above the motor, cooler outside air entering through a breach in a cubicle or the building general area (e.g., the outside door), would eventually be drawn into the cubicle, and out by the exhaust system. Thus, the ventilation and cooling function will not be affected by boundary breaches.

(continued)

BASES

ACTIONS

D.1.1, D.1.2, and D.1.3 (continued)

If two ECCS PREACS trains are inoperable due to loss of the pump room boundary, action must be taken within one hour to determine if the filtration capability is required (Action D.1.1). This is determined based on the Unit's operational ECCS leakage. If the current total ECCS leakage is less than the maximum allowable unfiltered leakage, then the filtration capability of ECCS PREACS is not immediately required and an extended period to restore operability can be applied. During this time, the ability to perform the ventilation exhaust/cooling function remains unaffected.

If the filtration capability of ECCS PREACS is not required, actions to restore the filtration function and restore the boundary to operable status within 14 days (Action D.l.3) are reasonable, consistent with:

(a) the dose analysis shows that no filtration is required when ECCS leakage is less than the maximum allowable unfiltered leakage,

(b) significant margin exists between operating limits and actual dose limits,

(c) operating history indicates that a sudden change in ECCS leakage to greater than the maximum allowable unfiltered leakage is not expected, and

(d) the time necessary to complete repairs and perform required testing may be significant.

In addition, ECCS leakage is required to be monitored by walking down the areas every 12 hours in order to determine whether or not filtration capability is required (Action D.1.2). Establishing monitoring on a 12 hour frequency is based on operating history, which indicated that a sudden change in ECCS leakage is not expected, and the conservatisms in the design basis dose calculations.

D.2

If total ECCS leakage is equal to or greater than the maximum allowable unfiltered leakage limit then the filtration capability of ECCS PREACS is required and actions must be taken to restore an operable ECCS pump room boundary within 24 hours. During the period that the ECCS pump room boundary

(continued)

BASES

ACTIONS

D.2 (continued)

is inoperable, appropriate compensatory measures consistent with the intent of GDC 19 should be utilized to protect control room operators from potential hazards such as radioactive contamination. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the condition. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of compensatory measures. The 24 hour Completion Time is a typically reasonable time to diagnose, plan and possibly repair, and test most problems with the ECCS pump room boundary.

E.1 and E.2

If the ECCS PREACS train(s) or ECCS pump room boundary 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

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 a month provides an adequate check on this system. Monthly heater operations dry out any moisture that may have accumulated in the charcoal and HEPA filters from humidity in the ambient air. The system must be operated $\geq$ 10 continuous hours with the heaters energized. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.2

This SR verifies that Safeguards Area exhaust flow and Auxiliary Building Central Exhaust subsystem flow, when actuated from the control room, diverts flow through the Auxiliary Building HEPA filter and charcoal adsorber assembly for the operating train. Exhaust flow is diverted manually through the filters in case of a DBA requiring their use. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.3

This SR verifies that the required ECCS PREACS 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 3.7.12.4

This SR verifies that Safeguards Area exhaust flow for the operating Safeguards Area fan is diverted through the filters on an actual or simulated actuation signal. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.5

This SR verifies the integrity of the ECCS pump room enclosure. The ability of the ECCS pump room to maintain a negative pressure, with respect to potentially uncontaminated adjacent areas, is periodically tested in a qualitative manner to verify proper functioning of each train of the ECCS PREACS. During the post accident mode of operation, the ECCS PREACS is designed to maintain a slight negative pressure in the ECCS pump room, with respect to adjacent areas, to prevent unfiltered LEAKAGE. A single train of ECCS PREACS is designed to maintain a negative pressure relative to adjacent areas. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Section 9.4.
2. UFSAR, Section 15.4.
3. Regulatory Guide 1.52 (Rev. 2).
4. 10 CFR 50, Appendix A.
5. NUREG-0800, Rev. 2, July 1981.
6. UFSAR, Figure 15.4-110

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B 3.7 PLANT SYSTEMS

B 3.7.13 Not Used

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B 3.7 PLANT SYSTEMS

B 3.7.14 Not Used

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B 3.7 PLANT SYSTEMS

B 3.7.15 Fuel Building Ventilation System (FBVS)

BASES

BACKGROUND

The FBVS discharges airborne radioactive particulates from the area of the fuel pool following a fuel handling accident. The FBVS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the fuel pool area.

The FBVS consists of ductwork, valves and dampers, instrumentation, and two fans.

The FBVS, which may also be operated during normal plant operations, discharges air from the fuel building.

The FBVS is discussed in the UFSAR, Sections 9.4.5 and 15.4.5 (Refs. 1 and 2, respectively) because it may be used for normal, as well as post accident functions.

APPLICABLE SAFETY ANALYSES

The FBVS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident involving handling recently irradiated fuel. The analysis of the fuel handling accident, given in Reference 2, assumes that all fuel rods in an assembly are damaged. The DBA analysis of the fuel handling accident assumes that the FBVS is functional with at least one fan operating. The amount of fission products available for release from the fuel building is determined for a fuel handling accident. Due to radioactive decay, FBVS is only required to be OPERABLE during 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). These assumptions and the analysis follow the guidance provided in Regulatory Guide 1.183 (Ref. 3).

The fuel handling accident analysis for the fuel building assumes all of the radioactive material available for release is discharged from the fuel building by the FBVS.

The FBVS satisfies Criterion 3 of the 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The FBVS is required to be OPERABLE and in operation. Total system failure could result in the atmospheric release from the fuel building exceeding the 10 CFR 50, Appendix A, GDC-19 (Ref. 4) limits for alternative source terms, in the event of a fuel handling accident involving handling recently irradiated fuel.

The FBVS is considered OPERABLE when the individual components are OPERABLE. The FBVS is considered OPERABLE when at least one fan is OPERABLE and in operation, the associated FBVS ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained. In addition, an OPERABLE FBVS must maintain a pressure in the fuel building pressure envelope £ -0.125 inches water gauge with respect to atmospheric pressure.

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 a need for fuel building isolation is indicated.

APPLICABILITY

During movement of recently irradiated fuel in the fuel handling area, the FBVS is required to be OPERABLE to alleviate the consequences of a fuel handling accident.

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

When the FBVS is inoperable or not in operation during movement of recently irradiated fuel assemblies in the fuel building, action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of recently irradiated fuel assemblies in the fuel building. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies the integrity of the fuel building pressure envelope. 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 FBVS. The FBVS is designed to maintain a slight negative pressure in the fuel building, to prevent unfiltered LEAKAGE. The FBVS is designed to maintain a ≤ -0.125 inches water gauge with respect to atmospheric pressure. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.4.5.
2. UFSAR, Section 15.4.5.
3. Regulatory Guide 1.183, July 2000.
4. 10 CFR 50, Appendix A, GDC-19.

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B 3.7 PLANT SYSTEMS

B 3.7.16 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. 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 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in the UFSAR, Section 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in the UFSAR, Section 15.4.5 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The minimum water level in the fuel storage pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.183 (Ref. 4). The resultant 2 hour dose per person at the exclusion area boundary is within the Regulatory Guide 1.183 limits.

According to Reference 4, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a fuel handling accident. With 23 ft of water, the assumptions 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 all fuel rods fail, although analysis shows that only the first few rows fail from a hypothetical maximum drop.

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 storage and movement within the fuel storage pool.
APPLICABILITY	This LCO applies during movement of irradiated fuel assemblies in the fuel storage pool, since the potential for a release of fission products exists.
ACTIONS	A.1 Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. 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. 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.
SURVEILLANCE REQUIREMENTS	SR 3.7.16.1 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.16.1 (continued) During refueling operations, the level in the fuel storage pool is in equilibrium with the refueling canal, and the level in the refueling canal is checked daily in accordance with SR 3.9.7.1.
REFERENCES	1. UFSAR, Section 9.1.2. 2. UFSAR, Section 9.1.3. 3. UFSAR, Section 15.4.5. 4. Regulatory Guide 1.183, July 2000.

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B 3.7 PLANT SYSTEMS

B 3.7.17 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

The water in the spent fuel storage pool contains soluble boron, which results in large subcriticality margins under normal operating conditions. However, the NRC guidelines assume accident conditions, such as loss of all soluble boron or misloading of a fuel assembly. In these cases, the subcriticality margin is allowed to be smaller, but in all cases must be less than 1.0. This subcriticality margin is maintained by storing the fuel assemblies in the fuel storage pool in a geometry which limits the reactivity of the fuel assemblies and by the use of soluble boron in the fuel storage pool water. The required geometry for fuel assembly storage in the fuel storage pool is described in LCO 3.7.18, "Spent Fuel Pool Storage." The accident analyses assume the presence of soluble boron under accident conditions, such as the misloading of a fuel assembly into a location not allowed by LCO 3.7.18, a loss of cooling to the fuel storage pool resulting in a temperature increase of the fuel storage pool water, or a dilution of the boron dissolved in the fuel storage pool.

A general description of the fuel storage pool design is given in the UFSAR, Section 9.1.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

Criticality of the fuel assemblies in the fuel storage pool racks is prevented by the design of the rack and by administrative controls related to fuel storage pool boron concentration, fuel assembly burnup credit, and fuel storage pool geometry (Ref. 2). There are three basic acceptance criteria which ensure conformance with the design bases (Ref. 3). They are:

a. $k_{eff} < 1.0$ assuming no soluble boron in the fuel storage pool,

b. A soluble boron concentration sufficient to ensure $k_{eff} < 0.95$, and

c. An additional amount of soluble boron sufficient to offset the maximum reactivity effects of postulated accidents and to account for the uncertainty in the computed reactivity of fuel assemblies.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The postulated accidents considered when determining the required fuel storage pool boron concentration are the misloading of a fuel assembly, an increase in fuel storage pool temperature, and boron dilution. Analyses have shown that the amount of boron required by the LCO is sufficient to ensure that the most limiting misloading of a fuel assembly results in a $k_{eff} < 0.95$. The boron concentration limit also accommodates decreases in water density due to temperature increases in the fuel storage pool. Analyses have also shown that there is sufficient time to detect and mitigate a boron dilution event prior to exceeding the design basis of $k_{eff} < 0.95$. The fuel storage pool analyses do not credit the Boraflex neutron absorbing material in the fuel storage pool racks.

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 ≥ 2600 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses which take credit for soluble boron and for fuel loading restrictions based on fuel enrichment and burnup. The fuel loading restrictions are described in LCO 3.7.18. The fuel storage pool boron concentration limit, when combined with fuel burnup and geometry limits in LCO 3.7.18, ensures that the fuel storage pool k_{eff} meets the limits in Section 4.3, "Design Features."

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel storage pool. The required boron concentration ensures that the k_{eff} limits in Section 4.3 are met when fuel is stored in the fuel storage pool.

ACTIONS

A.1 and A.2

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

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

(continued)

BASES

ACTIONS	A.1 and A.2 (continued) of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Prior to resuming movement of fuel assemblies, the concentration of boron must be restored to within limit. This does not preclude movement of a fuel assembly to a safe position. 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 3.7.17.1 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 9.1.2. 2. UFSAR, Section 4.3.2.7. 3. UFSAR, Section 3.1.53.

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B 3.8 PLANT SYSTEMS

B 3.7.18 Spent Fuel Pool Storage

BASES

BACKGROUND	The fuel storage pool contains racks which hold the fuel assemblies. The arrangement of the fuel assemblies in the fuel racks can be used to limit the interaction of the fuel assemblies and the resulting reactivity of the fuel in the fuel storage pool. The geometrical arrangement is based on classifying fuel assemblies as "high reactivity" or "low reactivity" based on the burnup and initial enrichment of the fuel assemblies. A 5 x 5 fuel location matrix is employed with acceptable locations for high and low reactivity fuel assemblies. Fuel assemblies may also be stored in fuel locations not associated with a storage matrix if the assemblies meet certain requirements. Storing the fuel assemblies in the locations required by the LCO ensures a fuel storage pool k_{eff} < 1.0 for normal conditions. In addition, the water in the spent fuel storage pool contains soluble boron, which results in large subcriticality margins under normal operating conditions. However, the NRC guidelines assume accident conditions, such as loss of all soluble boron or misloading of a fuel assembly. In these cases, the subcriticality margin is allowed to be smaller, but in all cases must be less than 1.0. This subcriticality margin is maintained by storing the fuel assemblies as described in the LCO and by the use of soluble boron in the fuel storage pool water as required by LCO 3.7.17, "Fuel Storage Pool Boron Concentration." The accident analyses assume the presence of soluble boron under accident conditions, such as the misloading of a fuel assembly into a location not allowed by LCO 3.7.18, a loss of cooling to the fuel storage pool resulting in a temperature increase of the fuel storage pool water, or a dilution of the boron dissolved in the fuel storage pool. A general description of the fuel storage pool design is given in the UFSAR, Section 9.1.2 (Ref. 1).
APPLICABLE SAFETY ANALYSES	Criticality of the fuel assemblies in the fuel storage pool racks is prevented by the design of the rack and by administrative controls related to fuel storage pool boron concentration, fuel assembly burnup credit, and fuel storage

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

pool geometry (Ref. 2). There are three basic acceptance criteria which ensure conformance with the design bases (Ref. 3). They are:

a. k_{eff} < 1.0 assuming no soluble boron in the fuel storage pool,

b. A soluble boron concentration sufficient to ensure k_{eff} < 0.95, and

c. An additional amount of soluble boron sufficient to offset the maximum reactivity effects of postulated accidents and to account for the uncertainty in the computed reactivity of fuel assemblies.

The postulated accidents considered when determining the required fuel storage pool arrangement and minimum boron concentration are the misloading of a fuel assembly, an increase in fuel storage pool temperature, and boron dilution. Analyses have shown that a combination of the fuel storage pool geometric arrangement and the amount of boron required by the LCO is sufficient to ensure that the most limiting misloading of a fuel assembly results in a k_{eff} < 0.95.

The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The restrictions on the placement of fuel assemblies within the spent fuel pool, in accordance with Figures 3.7.18-1 and 3.7.18-2, in the accompanying LCO, ensures the k_{eff} of the spent fuel storage pool will always remain < 1.0. Figure 3.7.18-1 is used to determine if a fuel assembly is acceptable for storage without use of a fuel assembly matrix. Based on the initial enrichment and burnup, a fuel assembly may be stored without using a fuel assembly matrix, or must be stored in a high or low reactivity location of a fuel assembly matrix. Figure 3.7.18-2 describes the fuel assembly matrix storage configuration. These storage restrictions, when combined with the fuel storage pool boron concentration limit in LCO 3.7.17, ensure that the fuel storage pool k_{eff} meets the limits in Section 4.3, "Design Features."

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in the fuel storage pool.

BASES

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 Figure 3.7.18-1 and Figure 3.7.18-2, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with the LCO.

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 3.7.18.1

This SR verifies by a combination of visual inspection and administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with Figure 3.7.18-1 and the fuel assembly storage location is in accordance with Figure 3.7.18-2.

REFERENCES

1. UFSAR, Section 9.1.2.

2. UFSAR, Section 4.3.2.7.

3. UFSAR, Section 3.1.53.

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B 3.7 PLANT SYSTEMS

B 3.7.19 Component Cooling Water (CC) System

BASES

BACKGROUND

The CC System provides a heat sink for the removal of process and operating heat from components during normal operation. The CC 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 CC System consists of four subsystems shared between units. Each subsystem consists of one pump and one heat exchanger. The design basis of the CC System is a fast cooldown of one unit while maintaining normal loads on the other unit. Three CC subsystems are required to accomplish this function. With only two CC subsystems available, a slow cooldown of one unit while maintaining normal loads on the other unit can be accomplished. The removal of normal operating heat loads (including common systems) requires two CC subsystems. During normal operation, the CC subsystems are cross connected between the units with two CC pumps and four CC heat exchangers in operation. Two pumps are normally running, with the other two in standby. A vented surge tank common to all four pumps ensures that sufficient net positive suction head is available.

The CC System serves no accident 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 CC System is not designed to withstand a single failure. The CC System supports the Residual Heat Removal (RHR) System. The RHR system does not perform a design basis accident mitigation function.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the UFSAR, Section 9.2.2 (Ref. 1). The principal function of the CC System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System.

BASES

APPLICABLE SAFETY ANALYSES

The CC System serves no accident mitigation function. The CC System functions to cool the unit from RHR entry conditions (T_{cold} < 350°F), to T_{cold} < 140°F. The time required to cool from 350°F to 140°F is a function of the number of CC and RHR trains operating. The CC System is designed to reduce the temperature of the reactor coolant from 350°F to 140°F within 16 hours based on a service water temperature of 95°F and having two CC subsystems in service for the unit being cooled down.

The CC System has been identified in the probabilistic safety assessment as significant to public health and safety. The CC System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Should the need arise to cooldown one unit quickly while the other unit is operating, three CC subsystems would be needed - two to support the quick cooldown of one unit and one to support the normal heat loads of the operating unit. To ensure this function can be performed a total of three CC subsystems shared with the other unit are required to be OPERABLE.

A CC subsystem is considered OPERABLE when:

a. The pump and common surge tank are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the function are OPERABLE.

Each CC subsystem is considered OPERABLE if it is operating or if it can be placed in service from a standby condition by manually unisolating a standby heat exchanger and/or manually starting a standby pump.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CC System is a normally operating system. In MODE 4 the CC System must be prepared to perform its RCS heat removal function, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CC System are determined by the systems it supports.

BASES

ACTIONS

A.1

If one required CC subsystem is inoperable, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CC subsystems are adequate to perform the heat removal function. The 7 day Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE subsystems.

B.1 and B.2

If the required CC subsystem 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 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.

C.1 and C.2

If two required CC subsystems are inoperable, action must be taken to cool the unit to MODE 4 within 12 hours. Action must be initiated to place the unit in MODE 5, where the LCO does not apply, within 13 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

With no CC water available to supply the residual heat removal heat exchangers, action must be taken to cool the unit to MODE 4 within 12 hours. Alternate means to cool the unit must be found and the unit placed in MODE 5, where the LCO does not apply. 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 3.7.19.1

Verifying the correct alignment for manual, power operated, and automatic valves in the CC flow path to the RHR heat exchangers provides assurance that the proper flow paths exist for CC 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.2.

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 offsite (preferred) power (via normal and alternate feeds), the Alternate AC (AAC) diesel, and the onsite standby power sources (Train A(H) and Train B(J) emergency diesel generators (EDGs)). As required by GDC 17 (Ref. 1), the design of the preferred AC electrical power system provides independence and redundancy to ensure an acceptable (i.e., qualified) source of power to the Engineered Safety Feature (ESF) systems.

Additionally, the unit's electrical sources must include electrical sources from the other unit that are required to support the Service Water (SW), Main Control Room (MCR)/Emergency Switchgear Room (ESGR) Emergency Ventilation System (EVS), Auxiliary Building central exhaust system, or Component Cooling Water (CC) safety functions. This requirement could include both of the other unit's offsite circuits and EDGs for this unit.

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, for a given unit, must have a connection to a qualified offsite (preferred) power source and a dedicated EDG. Also, for each unit, the two qualified offsite sources must be independent of each other. A minimum of two independent qualified offsite sources connecting the 230/500 kV switchyard to each unit's ESF (emergency) buses is required. Since the Unit 1 and 2 offsite sources may be shared, a minimum of two sources are required for the station. To be considered independent, a qualified offsite source must be both electrically and physically separated from other offsite sources. This independence must be maintained during possible automatic switching operations such as is initiated following a Unit 2 trip when ESF bus 1J is connected to the station service bus 2B. In this situation, ESF bus 1J is transferred to reserve station service transformer (RSST) B.

(continued)

BASES

BACKGROUND (continued)

The 230/500 kV switchyard, which is an integral part of the transmission network, is the source of offsite (preferred) power to the station Class 1E electrical system. From the 230/500 kV switchyard, five electrically and physically separated circuits are available to provide AC power, through either the system reserve transformers (SRTs) and RSSTs or the station service transformers (SSTs), 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). Each one is "qualified" via analysis to show that they meet the requirements of GDc 17.

Certain required unit loads are energized in a predetermined sequence in order to prevent overloading the transformers supplying offsite power to the onsite Class 1E Distribution System. After the initiating signal is received, permanently connected loads and all automatically connected loads, via the load sequencing timing relays, needed to recover the unit or maintain it in a safe condition are energized.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated EDG. EDGs H and J are dedicated to ESF buses H and J, respectively. An EDG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Emergency Diesel Generator (EDG) Start Instrumentation"). After the EDG has started, it will automatically tie to its respective bus after offsite power is isolated as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The EDGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal or a momentary undervoltage condition. Following the loss of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the EDG is tied to the ESF bus, loads are then sequentially connected to their respective ESF bus by the sequencing timing relays. The specific ESF equipment's sequencing timer controls the permissive and starting signals to motor breakers to prevent overloading the EDG by automatic load application.

(continued)

BASES

BACKGROUND (continued)

In the event of a loss of preferred (offsite) power, the ESF electrical loads are automatically connected to the EDGs 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) without overloading the EDGs.

Ratings for Train H and Train J EDGs satisfy the requirements of Safety Guide 9 (Ref. 3). The continuous service rating of each EDG is 2750 kW with 3000 kW 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 Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. 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

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

A minimum of two qualified offsite circuits between the 230/500 kV switchyard and the onsite Class 1E Electrical Power System and two separate and independent EDGs for supplying the redundant trains for each unit ensure

(continued)

LCO (continued)

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 include the two 500-34.5 kV transformers and one 230-34.5 kV transformers (collectively referred to as the SRTs) that feed three independent 34.5 kV buses which supply the RSSTs. In addition, there are two 500 kV lines from the switchyard to the Unit 1 and Unit 2 generator step-up transformers and SSTs. These circuits are described in the UFSAR and are part of the licensing basis for the unit.

In addition, the required automatic load sequencing timing relays must be OPERABLE. A "required" load sequencing timing relay is one whose host component is capable of automatically loading onto an emergency bus.

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

Normally, the qualified offsite sources for the Unit 1 and 2 ESF buses are from the 34.5 kV buses 3, 4, and 5 which supply the RSSTs which feed the transfer buses. RSSTs A and B may be fed from the same 34.5 kV bus, but RSST C must be fed from a different 34.5 kV bus than RSST A and RSST B. The D, E, and F transfer buses supply the onsite electrical power to the four ESF buses for the two units. In addition to the normal alignment, the D and E transfer buses can be tied together via the 4160 V bus 0L installed as part of the AAC modifications.

ESF bus 1H is normally fed through the F transfer bus from RSST C. Station service bus 1B can provide an alternate preferred feed for the bus ESF 1H.

ESF bus 1J is normally fed through the D transfer bus from RSST A. Bus 1J has an alternate preferred feed from station service bus 2B. In addition, ESF bus 1J can be fed through D transfer bus from RSST B with breakers 05L1 and 05L3 on AAC bus 0L closed (backup alternate feed).

ESF bus 2H is normally fed through the E transfer bus from RSST B. Station service bus 2C can provide an alternate preferred feed for bus 2H. In addition, ESF bus 2H can be fed through E transfer bus from RSST A with breakers 05L1 and 05L3 on AAC bus 0L closed (backup alternate feed).

ESF bus 2J is normally fed through the F transfer bus from RSST C. Station service bus 1A can provide an alternate preferred feed for Bus 2J.

(continued)

BASES

LCO (continued)

The two 500 kV lines connecting each unit's main step-up and SSTs with the switchyard are the remaining qualified sources of offsite (preferred) power that are available to power ESF buses. For Unit 1, this source is normally available following a unit trip since there is an installed main generator breaker. Therefore, station service bus 1A and 1B, which provide the preferred alternate feeds to the 2J and 1H ESF buses, respectively, normally will not be affected. For Unit 2, where there is no installed main generator breaker, station service bus 2B and 2C, which provide the preferred alternate feeds to ESF buses 1J and 2H, respectively, will automatically transfer to RSST B and RSST C following a unit trip.

Each EDG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage or degraded voltage. This will be accomplished within 10 seconds. Each EDG 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 EDG in standby with the engine hot and EDG in standby with the engine at ambient conditions. Additional EDG capabilities must be demonstrated to meet required Surveillances.

Proper sequencing of loads is a required function for EDG OPERABILITY.

In the event of a loss of offsite (preferred) power supply to the emergency bus, the EDG will auto start and re-energize its associated bus. In this configuration the EDG will become inoperable due to the defeat of load sequencing timers. Upon completion of guidance in abnormal procedures for reconfiguration of the affected electrical bus to control loads, TS 3.8.1 Condition K may be exited as sequencing timing relays are no longer required as long as the associated emergency bus is not subsequently paralleled to another bus. The diesel can be considered operable which would allow exiting TS 3.8.1 Conditions B and H and remaining in TS 3.8.1 Condition A.

The other unit's offsite circuit(s) and EDG(s) are required to be OPERABLE to support the SW, MCR/ESGR EVS, Auxiliary Building central exhaust, and CC functions needed for this unit. These functions share components, pump or fans, which are electrically powered from both units.

(continued)

BASES

LCO (continued)

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 EDGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical.

APPLICABILITY

The AC sources and sequencing timing relays 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.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(s) 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 G, 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 EDG will not result in a complete loss of safety function of critical redundant required features. These features are powered from the redundant AC electrical power trains.

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ACTIONS

A.2 (continued)

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 EDGs are adequate to supply electrical power to Train H and Train J 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.

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

(continued)

BASES

ACTIONS

A.3 (continued)

offsite circuit and EDGs 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. If Condition A is entered while, for instance, an EDG is inoperable and that EDG 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, an EDG 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.

B.1

Condition B is entered for an inoperable EDG and requires the OPERABILITY of additional electrical sources for the allowed Completion Time of 14 days. The additional electrical sources required to be OPERABLE are the AAC diesel generator (DG) (Station Black Out diesel generator), and both EDGs of the other unit. If any of these additional sources are

(continued)

ACTIONS

B.1 (continued)

inoperable at the time an EDG becomes inoperable, or become inoperable with an EDG in Condition B, Condition C must also be entered for the inoperable EDG.

To ensure a highly reliable power source remains with an inoperable EDG, 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 an EDG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable EDG.

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:

a. An inoperable EDG exists; and

b. A required feature on the other train (Train H or Train J) is inoperable.

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

Discovering one required EDG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE EDG, results

(continued)

BASES

ACTIONS

B.2 (continued)

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 EDG 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 the OPERABLE EDG. If it can be determined that the cause of the inoperable EDG does not exist on the OPERABLE EDG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other EDG, the other EDG would be declared inoperable upon discovery and Condition I 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 EDG cannot be confirmed not to exist on the remaining EDG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that EDG.

In the event the inoperable EDG 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, including the other unit's EDGs. 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 EDG is not affected by the same problem as the inoperable EDG.

BASES

ACTIONS (continued)

B.4

In Condition B, the remaining OPERABLE EDG, offsite circuits, AAC DG, and the other unit's EDGs are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day 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 B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the EDG. At this time, an offsite circuit could again become inoperable, the EDG 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

To ensure a highly reliable electrical power source remains available when one EDG is inoperable, Condition C is established to monitor the OPERABILITY of the AAC DG and the other unit's EDGs. Condition B is entered any time an EDG becomes inoperable and the Required Actions and Completion Times are followed. Concurrently, if the AAC DG or one or more of the other unit's EDG(s) is inoperable, or become

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

inoperable, in addition to the Required Actions of Condition B, Required Actions C.1 and C.2 limit the time the EDG may be out of service to 72 hours. If the AAC DG or the other unit's EDG(s) is inoperable when the EDG becomes inoperable, the allowed outage time (AOT) is limited to 72 hours, unless the AAC DG and the other unit's EDG(s) are returned to OPERABLE status. If during the 72 hour Completion Time of C.1 or C.2, the AAC DG and the other unit's EDG(s) are returned to OPERABLE status, Condition C is exited and AOT is restricted by the Completion Time tracked in Condition B. If the AAC DG or one or more of the other unit's EDG(s) becomes inoperable at sometime after the initial EDG inoperability, Condition C requires the restoration of the EDG or the AAC DG and the other unit's EDG(s) within 72 hours or Condition L is required to be entered.

The 72 hour Completion Time is considered reasonable and takes into account the assumption in the probabilistic safety analysis (PSA) for potential core damage frequency.

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

Condition D is modified by a Note indicating that separate Condition entry is allowed for each offsite circuit on the other unit that provides electrical power to required shared components.

To provide the necessary electrical power for the SW, MCR/ESGR EVS, Auxiliary Building central exhaust, and CC functions for a unit, AC electrical sources of both units may be required to be OPERABLE. Action D is entered for one or more inoperable offsite circuit(s) on the other unit that is necessary to support required shared components. These shared components are the SW pump(s), MCR/ESGR EVS fan(s), Auxiliary Building central exhaust fan(s), and CC pumps. Required Action D.1 verifies the OPERABILITY of the remaining required offsite sources within an hour of the inoperability and every 8 hours thereafter. Since the Required Action only specifies "perform," a failure of the SR 3.8.1.1 acceptance criteria does not result in a Required Action not met.

(continued)

BASES

ACTIONS

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

The Completion Time for Required Action D.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 required shared component has no offsite power; and
b. A required shared component(s) in the same system is inoperable.

If at any time during the existence of Condition D (one offsite circuit inoperable on the other unit needed to supply electrical power for a required shared component) another required shared component in the same system subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power on the other unit that supports a required shared component and an additional required shared component in the same system inoperable, 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 circuits and EDGs that power the required shared components are adequate to support the SW, MCR/ESGR EVS, Auxiliary Building central exhaust system, and CC functions. The 24 hour Completion Time takes into account the component OPERABILITY of the remaining shared component(s), a reasonable time for repairs, and the low probability of a DBA occurring during this period.

Operation may continue in Condition D for a period of 72 hours. With one offsite circuit inoperable on the other unit supplying electrical power to a required shared component, the reliability of the SW, MCR/ESGR EVS, Auxiliary Building central exhaust system, and CC functions are degraded. The potential for the loss of offsite power to the other required shared components is increased, with the attendant potential for a challenge to SW, MCR/ESGR EVS, Auxiliary Building central exhaust system, and CC functions.

(continued)

ACTIONS

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

The required offsite circuit must be returned to OPERABLE status within 72 hours, or the support function for the associated shared component is considered inoperable. At that time, the required shared component must be declared inoperable and the appropriate Conditions of the LCO 3.7.8, "Service Water System," LCO 3.7.10, "MCR/ESGR Emergency Ventilation System," LCO 3.7.12, "Emergency Core Cooling System (ECCS) Pump Room Exhaust Air Cleanup System," and LCO 3.7.19, "Component Cooling Water (CC) System," must be entered. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources providing electrical power to the required shared components, a reasonable time for repairs and the low probability of a DBA occurring during this period of time.

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

To ensure a highly reliable power source remains with an inoperable EDG, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. Required Action E.1 verifies the OPERABILITY of the required offsite sources within an hour of the inoperability and every 8 hours thereafter. 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 be entered.

Required Action E.2 is intended to provide assurance that a loss of offsite power, during the period that an EDG is inoperable, does not result in a complete loss of the SW, MCR/ESGR EVS, Auxiliary Building central exhaust system, or CC functions.

The Completion Time for Required Action E.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 required shared component with an inoperable EDG; and
b. A required shared component(s) in the same system is inoperable.

(continued)

BASES

ACTIONS

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

If at any time during the existence of Condition E (one EDG inoperable on the other unit needed to supply electrical power for a required shared component) another required shared component subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering an EDG on the other unit that supports a required shared component and an additional required shared component inoperable, results in starting the Completion Times for the Required Action. 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 circuits and EDGs that power the required shared components are adequate to support the SW, MCR/ESGR EVS, Auxiliary Building central exhaust system, or CC functions. The 4 hour Completion Time takes into account the component OPERABILITY of the remaining shared components, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

Operation may continue in Condition E for a period of 14 days. With one EDG inoperable on the other unit supplying electrical power to a required shared component, the reliability of the respective Function is degraded. The potential for the loss of EDGs to the other required shared components is increased, with the attendant potential for a challenge to respective Function.

The required EDG must be returned to OPERABLE status within 14 days, or the support function for the associated shared component is considered inoperable. At that time, the required shared component must be declared inoperable and the appropriate Conditions of the LCOs 3.7.8, 3.7.10, 3.7.12, and 3.7.19 must be entered. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources providing electrical power to the required shared components, a reasonable time for repairs and the low probability of a DBA occurring during this period of time.

BASES

ACTIONS (continued)

F.1 and F.2

To ensure a highly reliable electrical power source remains available when one EDG is inoperable that is required to support a required shared component on the other unit, Condition F is established to monitor the OPERABILITY of the AAC DG and the LCO 3.8.1.b EDGs. Condition F is entered any time an EDG that is required to support a required shared component that receives its electrical power from the other unit becomes inoperable and the Required Actions and Completion Times are followed. Concurrently, if the AAC DG or one or more of this unit's EDG(s) is inoperable, or become inoperable, in addition to the Required Actions of Condition E, Required Actions F.1 and F.2 limit the time the EDG may be out of service to 72 hours. If the AAC DG or this unit's EDG(s) is inoperable when the other unit's EDG becomes inoperable, the AOT is limited to 72 hours, unless the AAC DG and this unit's EDG(s) are returned to OPERABLE status. If during the 72 hour Completion Time of F.1 or F.2, the AAC DG and this unit's EDG are return to OPERABLE status, Condition F is exited and AOT is restricted by the Completion Time tracked in Condition E. If the AAC DG or one or more of this unit's EDG(s) becomes inoperable at sometime after the initial EDG inoperability, Condition F requires the restoration of the AAC DG and this unit's EDG(s) within 72 hours or the supported shared component must be declared inoperable and LCOs 3.7.8, 3.7.10, 3.7.12, and 3.7.19 provides the appropriate restrictions.

The 72 hour Completion Time is considered reasonable and takes into account the assumption in the probabilistic safety analysis (PSA) for potential core damage frequency.

G.1 and G.2

Required Action G.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 safety functions. 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.

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains.

The Completion Time for Required Action G.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition G (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 G 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 EDGs 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.

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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.

H.1 and H.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 H are modified by a Note to indicate that when Condition H 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 H to provide requirements for the loss of one offsite circuit and one EDG, 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 H for a period that should not exceed 12 hours.

In Condition H, 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 G (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

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.

I.1

With Train H and Train J EDGs 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 EDGs inoperable, operation may continue for a period that should not exceed 2 hours.

J.1

With two LCO 3.8.1.c required EDGs inoperable, as many as two required shared and potentially required components have no remaining standby AC sources. Thus, with an assumed loss of offsite power condition, the required shared components powered from the other unit would be significantly degraded. Therefore, the required shared component would immediately be declared inoperable and LCOs 3.7.8, 3.7.10, 3.7.12, and 3.7.19 would provide the appropriate restrictions.

K.1 and K.2

Condition K is modified by a Note indicating that separate Condition entry is allowed for each inoperable sequencing timing relay.

(continued)

BASES

ACTIONS

K.1 and K.2 (continued)

Condition K is entered any time a required sequencing timing relay (STR) becomes inoperable. Required Action K.1 directs the entry into the Required Actions and Completion Times associated for the individual component served by the inoperable relay. The instrumentation signals that provide the actuation are governed by LCO 3.3.2, "Engineered Safety Features Actuation System Instrumentation" for safety injection (SI), Containment Spray (Containment Depressurization Actuation (CDA)) and LCO 3.3.5, "Loss of Power (LOP) Emergency Diesel Generator (EDG) Start Instrumentation" for the LOP.

The STRs 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. Required Action K.2 provides for the immediate isolation of the component(s) ability to automatically load on an emergency electrical bus with an inoperable STR. This provides an assurance that the component will not be loaded onto an emergency bus at an incorrect time. Improper loading sequence may cause the emergency bus to become inoperable. Rendering a component with an inoperable STR incapable of loading to the emergency bus prevents a possible overload condition. Upon implementation of Action K.2.1, the inoperable sequencing timing relay is no longer required. Required Action K.2.2 provides an alternative option for isolating the component with an inoperable STR from the emergency bus by allowing the associated EDG to be declared inoperable.

L.1 and L.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 unit systems.

BASES

ACTIONS (continued)

M.1

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

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with GDC 18 (Ref. 1). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the EDGs are in accordance with the recommendations of Safety Guide 9 (Ref. 3), Regulatory Guide 1.108 (Ref. 8)(subsequently replaced by Regulatory Guide 1.9 (Ref. 13)), and Regulatory Guide 1.137 (Ref. 9), 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 of 3740 V is 90% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 10), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the EDG are 59.5 Hz and 60.5 Hz, respectively. These values are < ±1% of the 60 Hz nominal frequency and are derived from the safety analysis assumptions for operation of ECCS pump criteria.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 the preferred or alternate power sources for Unit 1 or Unit 2, and that appropriate independence of offsite circuits is maintained. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 1 for SR 3.8.1.2) to indicate that all EDG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the EDGs are started from standby conditions. Standby conditions for an EDG mean that the diesel engine coolant and oil are being continuously circulated, as required, and temperature is being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of EDGs is limited, warmup is limited to this lower speed, and the EDGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2.

SR 3.8.1.7 requires that the EDG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 2) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2.

In addition to the SR requirements, the time for the EDG to reach steady state operation, unless the modified EDG start method is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.3

This Surveillance verifies that the EDGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of 90% to 100% of continuous rating (2500 to 2600 kW). A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the EDG is connected to the offsite source.

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

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (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 above the limit do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one EDG 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 EDG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level which is required. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of EDG operation at full load plus 10%.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during EDG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.5 (continued)

oil system. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. 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 the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. 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. Only one fuel oil transfer subsystem is required to support an OPERABLE EDG.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, 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 unit 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 unit shutdown and startup to determine that unit 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.

SR 3.8.1.9

Each EDG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the EDG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. For this unit, the single load for each EDG is 610 kW. This Surveillance may be accomplished by:

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

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

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

As required by IEEE-308 (Ref. 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 Safety Guide 9 (Ref. 3) recommendations for response during load sequence intervals.

The 3 seconds specified is equal to 60% 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 EDG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The Note ensures that the EDG 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 ≤ 0.9. This power factor is representative of the actual inductive loading an EDG would see under design basis accident conditions. Under certain conditions, however, the Note allows the surveillance to be conducted at a power factor other than ≤ 0.9. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the EDG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the EDG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding the EDG excitation limits.

BASES

SURVEILLANCE (continued)

SR 3.8.1.10

Consistent with the recommendations of Regulatory Guide 1.108 (Ref. 8), paragraph 2.a.(1), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the EDG. It further demonstrates the capability of the EDG to automatically achieve the required voltage and frequency within the specified time.

The EDG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

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 EDG 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, and not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the EDG systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated, as required, and temperature

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge 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 unit 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 the unit shutdown and startup to determine that unit 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 this assessment.

SR 3.8.1.11

This Surveillance demonstrates that the EDG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.11.d and SR 3.8.1.11.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the EDG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or high pressure

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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 EDG 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of this 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 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 unit 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 the unit shutdown and startup to determine that unit safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

BASES

SURVEILLANCE (continued)

SR 3.8.1.12

This Surveillance demonstrates that EDG noncritical protective functions (e.g., high jacket water temperature) are bypassed on actual or simulated signals from an ESF actuation, a loss of voltage, or a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed and generator differential current) trip the EDG to avert substantial damage to the EDG unit. 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 EDG 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 EDG.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 EDG 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 unit 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 unit shutdown and startup to determine that unit 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

Regulatory Guide 1.108 (Ref. 8), paragraph 2.a.(3), provides an acceptable method to demonstrate once per 18 months that the EDGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent from 105% to 110% of the continuous duty rating and the remainder of the time at a load equivalent from 90% to 100% of the continuous duty rating of the EDG. The EDG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for 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 EDG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit 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 unit 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a unit shutdown and startup to determine that unit 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. Note 3 ensures that the EDG 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 ≤ 0.9. This power factor is representative of the actual inductive loading an EDG 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 ≤ 0.9. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the EDG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the EDG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding the EDG excitation limits.

SR 3.8.1.14

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the EDG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY. The requirement that the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

diesel has operated for at least 2 hours at full load conditions, or after operating temperatures reach a stabilized state, prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all EDG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.15

Consistent with the recommendations of Regulatory Guide 1.108 (Ref. 8), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the EDG to the offsite source can be made and the EDG 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 EDG to reload if a subsequent loss of offsite power occurs. The EDG is considered to be in ready to load status when the EDG is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequencing timing relays are reset. EDG loading of the emergency bus is limited to normal energized loads.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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 unit 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

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 unit shutdown and startup to determine that unit 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.

SR 3.8.1.16

Under accident conditions, with a loss of offsite power, safety injection, containment spray, or recirculation spray, loads are sequentially connected to the bus by the automatic load sequencing timing relays. The sequencing timing relays control the permissive and starting signals to motor breakers to prevent overloading of the EDGs due to high motor starting currents. The load sequence time interval tolerances, listed in the Technical Requirements Manual (Ref. 12), ensure that sufficient time exists for the EDG 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 based on operating experience, equipment reliability, and plant risk and 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 unit safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

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 unit shutdown and startup to determine that unit 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.

SR 3.8.1.17

In the event of a DBA coincident with a loss of offsite power, the EDGs 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 EDG operation, as discussed in the Bases for SR 3.8.1.10, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the EDG 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for EDGs. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

(e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines unit 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 the unit shutdown and startup to determine that unit 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 this assessment.

SR 3.8.1.18

This Surveillance demonstrates that the EDG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the EDGs are started simultaneously.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is to minimize wear on the EDG during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. UFSAR, Chapter 3.
2. UFSAR, Chapter 8.
3. Safety Guide 9, March 1971.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.

BASES

REFERENCES (continued)

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. Regulatory Guide 1.108, Rev. 1, August 1977.

9. Regulatory Guide 1.137, Rev. 1, October 1979.

10. ASME Code for Operation and Maintenance of Nuclear Power Plants.

11. IEEE Standard 308-1971.

12. Technical Requirements Manual.

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 recently irradiated fuel assemblies 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 AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, AC electrical power is only required to mitigate fuel handling accident involving handling recently irradiated fuel. (i.e., fuel that has occupied part of a critical reactor core within a time frame established by analysis. The term recently is defined as all irradiated fuel assemblies, until analysis is performed to determine a specific time frame.)

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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:

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 emergency diesel generator (EDG) 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

(continued)

BASES

LCO (continued)

powered from offsite power. An OPERABLE EDG, associated with the distribution system trains 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 EDG 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 handling recently irradiated fuel).

The qualified offsite circuit must be capable of maintaining rated 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.

Offsite circuits consist of 34.5 kV buses 3, 4, and 5 supplying the Reserve Station Service Transformer(s) (RSST) which feed the transfer buses. The D, E, and F transfer buses supply the onsite electrical power to the four emergency buses for the two units. Unit 1 emergency bus H is fed through the F transfer bus from the C RSST. Unit 1 emergency bus J is fed through the D transfer bus from the A RSST. Unit 1 station service bus 1B can be an alternate feed for Unit 1 H emergency bus, while Unit 1 J bus may be fed from Unit 2 station service bus 2B. Unit 2 emergency bus H is fed through the E transfer bus from the B RSST. Unit 2 emergency bus J is fed through the F transfer bus from the C RSST. Unit 2 station service bus 2C can be an alternate feed for Unit 2 H emergency bus, while Unit 2 J bus may be fed from Unit 1 station service bus 1A. In addition, E transfer bus can be a backup alternate feed to Unit 2 H bus (fed from RSST A through the D transfer bus and OL bus). The RSSTs can be fed by any 34.5 kV bus (3, 4, or 5) provided RSSTs A and B are fed from a different 34.5 kV bus than RSST C.

The EDG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage or degraded voltage. The EDG 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 bus. These capabilities are required to be met from a variety of initial conditions such as EDG in standby with the engine hot and the EDG in standby at ambient conditions.

Proper sequencing of loads is a required function for EDG OPERABILITY.

(continued)

BASES

LCO (continued)

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 recently irradiated fuel assemblies 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 handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 300 hours) are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the 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

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 recently irradiated 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.

BASES

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required 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 EDG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of recently irradiated 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 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

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

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 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.11 and SR 3.8.1.17 are not required because the ESF actuation signals are not required to be OPERABLE. SR 3.8.1.18 is excepted because starting independence is not required with the EDG(s) that is not required to be OPERABLE.

This SR is modified by a Note. The reason for this Note is to preclude requiring the required OPERABLE EDG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude de-energizing 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 EDG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the EDG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil and Starting Air

BASES

BACKGROUND

The fuel oil storage system has sufficient capacity to operate two EDGs for a period of 7 days with each supplying the maximum post loss of coolant accident load demand discussed in the UFSAR, Section 9.5.4.2 (Ref. 1). This onsite fuel oil capacity is sufficient to operate the EDGs for longer than the time to replenish the onsite supply from outside sources.

The fuel oil storage system consists of two underground tanks. Fuel oil is transferred from an underground tank to each EDG day tank by a lead fuel oil transfer pump. An additional underground tank and fuel oil transfer pump is associated with each EDG day tank to provide a redundant subsystem. Independent level switches on the day tank operate the lead and backup fuel oil transfer subsystems. Only one fuel oil transfer subsystem is required for the EDG to be considered OPERABLE. All outside tanks, pumps, and piping are located underground or in a missile protected area.

For proper operation of the standby EDGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

Each EDG has an air start system that contains two separate and independent subsystems. Normally, each subsystem is aligned to provide starting air to the associated EDG. Each subsystem consists of a receiver and a compressor, however, the receiver pressurized to ≥ 175 psig is the only component required to maintain operability of each diesel starting air subsystem. Only one air start receiver is required for the EDG to be considered OPERABLE.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 4), and in the UFSAR, Chapter 15 (Ref. 5), assume Engineered Safety

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Feature (ESF) systems are OPERABLE. The EDGs 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.

The DBA and transient analyses assume the operation of one EDG associated with the unit on which an accident is postulated to occur and the operation of one EDG on the unit which is unaffected by the accident to support shared systems. LCO 3.8.1 requires two EDGs to be OPERABLE and one EDG from the other unit to be OPERABLE. However, only sufficient fuel oil to operate one EDG and one EDG on the other unit is required to satisfy the assumptions of the DBA and transient analysis and to support EDG OPERABILITY.

Since diesel fuel 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 two EDGs. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 2 days, supports the availability of EDGs 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. EDG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown."

One air start receiver is required to ensure EDG OPERABILITY. The required starting air receiver is required to have a minimum of 175 psig to provide the EDG with more than one start attempt 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

(continued)

BASES

APPLICABILITY (continued)

after an AOO or a postulated DBA. Since stored diesel fuel oil and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil and starting air are required to be within limits when the EDG(s) is required to be OPERABLE.

All four EDGs (two per unit) are normally associated with both tanks which make up the fuel oil storage system. All EDGs that are required to be OPERABLE are associated with the fuel oil storage system. The determination of which EDGs are required to be OPERABLE is based on the requirements of LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

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

<u>A.1, A.2, A.3, and A.4</u>

In this Condition, an underground fuel oil storage tank is not within limits for the purpose of tank repair or inspection. Every ten years each fuel oil tank must be inspected. Because both tanks are the source of fuel oil for all EDGs on both units, a dual unit outage would be required in order to provide the necessary time to complete the required maintenance or inspection. Prior to removal of the tank for repairs or inspection, verify 50,000 gallons of replacement fuel oil is available offsite and transportation is available to deliver that volume of fuel oil within 48 hours. Restrictions are placed on the remaining fuel oil storage tank and the 210,000-gallon above ground tank. Under this Condition, verification of the redundant fuel oil tank is required to confirm the required minimum amount of diesel fuel oil. In addition, the above ground tank, used to supply make up to the underground tanks, is required to be verified to contain the minimum level corresponding to 100,000 gallons. Verifications of onsite fuel oil are required on a 12 hour frequency to ensure an adequate source

(continued)

BASES

ACTIONS (continued)

of fuel oil to the EDGs remains available. The underground fuel oil tank that is being inspected or repaired must be restored within limits in 7 days. This time is considered reasonable based on the required maintenance and the requirements provided by the Required Actions.

A note is provided which permits a one-time extension of the 7-day Completion Time to 14 days for each fuel oil storage tank. To extend the Completion Time from 7 to 14 days, the Incremental Conditional Core Damage Probability and incremental conditional large early release probability limits of RG 1.177 were used as the criteria to identify potentially risk significant configurations. The results of the analysis identified several components that should not be scheduled for planned maintenance during the one-time extended Completion Time. The following components will not be scheduled for planned maintenance during the extended Completion Time nor will the 14-day Completion Time be entered with any of the following components out of service:

- Reserve Station Service Transformers 1-EP-ST 2A, 2B, and 2C
- Transfer Buses D, E, and F
- Buses 1 and 2
- Transformers 1 and 2
- Breakers L102 and L202
- Emergency Diesel Generators 1/2 EE-EG-1/2 H and J
- Emergency Switchgear Air Handlers 1/2-HV-AC-6/7
- Charging Pumps 1/2 CH-P-1A/B/C (two pumps on the same unit)

In the event one of the components above become inoperable during the extended Completion Time the risk will be managed in accordance with the Tier 3, Risk-Informed Plant Configuration Control Management practices.

(continued)

BASES

ACTIONS (continued)

In addition, the following compensatory measure will be established and implemented prior to entry and while in the extended AOT:

1. The condition of the offsite power supply and switchyard will be evaluated prior to entering the extended EDG UFOST CT for elective maintenance.

2. Determine acceptable grid conditions for entering an extended EDG UFOST CT to perform elective maintenance. An extended EDG UFOST CT will not be entered to perform elective maintenance when grid stress conditions are high.

3. No elective maintenance will be scheduled in the switchyard that would challenge offsite power availability and no elective maintenance will be scheduled on the main, auxiliary [station service], or startup [reserve station service] transformers associated with the unit during the proposed extended EDG UFOST CT.

4. The system dispatcher will be contacted once per day to ensure no significant grid perturbations are expected during the extended EDG UFOST CT.

5. The turbine-driven AFW pump will not be removed from service for planned maintenance activities during the extended EDG UFOST CT.

6. Operating crews will be briefed on the EDG UFOST work plan and procedural actions regarding:

   LOOP and Station Black Out
   Reactor Coolant System bleed and feed

7. Weather conditions will be evaluated prior to entering the extended EDG CT for elective maintenance. An extended EDG UFOST CT will not be entered for elective maintenance purposes if official weather forecasts are predicting severe conditions (tornado or thunderstorm warnings).

8. No elective maintenance will be scheduled for the plant DC system.

(continued)

BASES

ACTIONS (continued)

9. Perform an assessment of the overall impact of maintenance on plant risk using a Configuration Risk Management Program before entering TS for planned EDG UFOST maintenance activities.

B.1

In this Condition, the 7 day fuel oil supply is not available. The EDG fuel oil transfer pumps are aligned so that the lead pump for each EDG takes suction on the 'A' tank. The backup pumps are aligned to take suction on the 'B' tank. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as 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 EDG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period. This Condition applies for reasons other than Condition A.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.2. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated EDG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the EDG fuel oil stored in the below ground tanks.

BASES

ACTIONS (continued)

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.2 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 an EDG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the EDG would still be capable of performing its intended function.

E.1

With the one required starting air receiver pressure < 175 psig, sufficient capacity for several EDG start attempts does not exist. However, as long as the receiver pressure is > 150 psig, there is adequate capacity for at least one start attempt, and the EDG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the EDG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most EDG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time not met, or one or more EDG's fuel oil or the required starting air receiver not within limits for reasons other than addressed by Conditions A through E, the associated EDG(s) may be incapable of performing its intended function and must be immediately declared inoperable. Only one starting air receiver is required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support two EDGs' operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.2

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-88 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-89 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27× and ≤ 39× when tested in accordance with ASTM D287-82 (Ref. 6), a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil is checked for water and sediment content within limits when tested in accordance with ASTM D1796-83 (Ref. 6).

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

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 D975-89 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-89 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D4294-98 (Ref. 6), ASTM D1552-88 (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 EDG operation. This Surveillance ensures the availability of high quality fuel oil for the EDGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, 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 D6217-98 (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. Each tank is considered and tested separately.

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 3.8.3.3

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each EDG is available. The system design requirements were verified for a minimum of five engine start cycles without recharging. A start cycle is measured in terms of time

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

(seconds of cranking). With receiver pressurized > 150 psig, there is adequate capacity for at least one start. The pressure specified in this SR is intended to reflect the lowest value at which more than one start can be accomplished.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.4

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 EDG 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. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.5.4.2.
2. Regulatory Guide 1.137.
3. ANSI N195-1976, Appendix B.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.

BASES

REFERENCES (continued)

6. ASTM Standards: D4057-88; D975-89; D1522-88; D2622-82; D2276-82; D4292-98; D6217-98; D287-82; D1796-83.

7. ASTM Standards, D975, Table 1, 1989.

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources—Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred AC vital bus power (via inverters). As required 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 Safety Guide 6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of two independent and redundant safety related Class 1E DC electrical power subsystems (Train H and Train J). Each subsystem consists of two 125 VDC batteries, the associated battery charger(s) for each battery, and all the associated control equipment and interconnecting cabling. A spare battery charger is installed on each train and can be substituted for either of the train's chargers.

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.

The Train H and Train J 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 Systems—Operating," and LCO 3.8.10, "Distribution Systems—Shutdown."

Each battery has adequate storage capacity to carry the required load continuously for at least 2 hours.

(continued)

BASES

BACKGROUND (continued)

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.

The criteria for sizing large lead storage batteries are defined in IEEE-485 (Ref. 5).

Each Train H and Train J DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient 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 the UFSAR, Chapter 8 (Ref. 4).

The EDG DC electrical power system consists of the battery, battery charger, and interconnecting cabling to supply the required DC voltage to allow the associated EDG components to perform the required safety function.

For the other unit, the DC electrical power system provides control power for breakers and electrical power for solenoid operated valves that are needed to support operation of each required Service Water (SW) pump, Main Control Room (MCR)/Emergency Switchgear Room (ESGR) Emergency Ventilation System (EVS) fan, Auxiliary Building central exhaust fan, and Component Cooling Water (CC) pump. SW, MCR/ESGR EVS, Auxiliary Building central exhaust system, and CC are shared systems.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 6), and in the UFSAR, Chapter 15 (Ref. 7), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the emergency auxiliaries and control and switching during all MODES of operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 OPERABILITY of the EDG DC electrical power system ensures the EDG may perform its required safety function.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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).

The EDG DC electrical power system consists of the battery, battery charger, and interconnecting cabling to supply the required DC voltage to allow the associated EDG components to perform the required safety function.

An OPERABLE DC electrical power subsystem requires all required batteries and respective chargers to be operating and connected to the associated DC bus(es).

Additionally, the unit's electrical sources must include DC sources from the other unit that are required to support the SW, MCR/ESGR EVS, or CC safety functions. Control power for breakers and electrical power for solenoid operated valves are examples of support systems required to be OPERABLE that are needed for the operation of each required SW pump, MCR/ESGR EVS fan,

(continued)

BASES

LCO (continued)

Auxiliary Building central exhaust fan, and CC pump. SW, MCR/ESGR EVS, and CC are shared systems.

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 EDG DC system is required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure the OPERABILITY of the associated EDG in accordance with LCO 3.8.1. In MODES 5 or 6, the OPERABILITY requirements of the EDG DC system are determined by the EDGs that they support in accordance with LCO 3.8.2.

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

Condition A 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 LCO 3.8.4.a DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining LCO 3.8.4.a DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. For the Station batteries, a spare battery charger may be substituted for the normal charger without

(continued)

BASES

ACTIONS

A.1 (continued)

entry into Condition A. Since a subsequent worst case single failure would, however, result in the complete loss of the remaining 125 VDC electrical power subsystems with attendant loss of ESF functions, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 8) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

B.1 and B.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 unit systems. The Completion Time to bring the unit to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 8).

C.1

Condition C represents the loss of the ability of the EDG DC system (e.g., inoperable battery charger or inoperable battery) to supply necessary power to the associated EDG. In this condition, the associated EDG is immediately declared inoperable and the associated Conditions or Required Actions of LCO 3.8.1 are followed.

D.1

Condition D represents the loss of one or more required LCO 3.8.4.c DC electrical power subsystem(s) needed to support the operation of required shared components on the other unit. SW, MCR/ESGR EVS, and CC are shared systems. In this condition, the associated required shared components are declared inoperable immediately. The associated Conditions or Required Actions of LCO 3.7.8, "Service Water System,"

(continued)

BASES

ACTIONS

D.1 (continued)

LCO 3.7.10, "MCR/ESGR Emergency Ventilation Systems," LCO 3.7.12, "Emergency Core Cooling System Pump Room Exhaust Air Cleanup System," and LCO 3.7.19, "Component Cooling Water (CC) System," are followed.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

For Station and EDG batteries, verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.2

Visual inspection of both Station and EDG batteries to detect corrosion of the battery cells and connections, or measurement of the resistance of each intercell, interrack, intertier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.4.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function). The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.4 and SR 3.8.4.5

Station and EDG battery visual inspection and resistance measurements of intercell, interrack, intertier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection. The removal of visible corrosion is a preventive maintenance SR. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.6 and SR 3.8.4.7

SR 3.8.4.6 requires that each Station battery charger be capable of supplying ≥ 270 amps and ≥ 125 V for ≥ 4 hours. These requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

SR 3.8.4.7 requires that each EDG battery charger be capable of supplying ≥ 10 amps and ≥ 125 V for ≥ 4 hours. These values are based on the design requirements of the charger.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 and SR 3.8.4.7 (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The spare charger for the Station batteries is required to be tested to the same criteria as the normal charger if it is to be used as a substitute charger.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.8

A Station battery service test is a special test of 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 requirements as specified in Reference 4.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by three Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

A modified performance 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 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 published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

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.

Note 2 allows the performance discharge test in lieu of the service test.

The reason for Note 3 is that performing the Surveillance on the Station batteries would 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 unit 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 the unit shutdown and startup to determine that unit 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 this assessment.

SR 3.8.4.9

A battery performance discharge test for Station and EDG batteries is a test of constant current capacity of a battery to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is described in the Bases for SR 3.8.4.8. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.9.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.9 (continued)

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 9) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and 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. 9), 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. The 60 month Frequency is consistent with the recommendations in IEEE-450 (Ref. 9) and the 18 month Frequency is consistent with operating experience.

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 for the Station batteries. 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 unit 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 the unit shutdown and startup to determine that unit 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 this assessment.

BASES

REFERENCES

1. UFSAR, Chapter 3.
2. Safety Guide 6, March 10, 1971.
3. IEEE-308-1971.
4. UFSAR, Chapter 8.
5. IEEE-485-1983, June 1983.
6. UFSAR, Chapter 6.
7. UFSAR, Chapter 15.
8. Regulatory Guide 1.93, December 1974.
9. IEEE-450-1987.
10. Regulatory Guide 1.32, February 1977.
11. Regulatory Guide 1.129, December 1974.

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources—Shutdown

BASES

BACKGROUND	A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the emergency auxiliaries and control and switching during all MODES of operation. The EDG DC system provides power for the required EDG as described in LCO 3.8.2, "AC Sources—Shutdown."

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 recently irradiated fuel assemblies 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 DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, 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 a time frame established by analysis. The term recently is defined as all irradiated fuel assemblies, until analysis is performed to determine a specific time frame.)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The DC electrical power subsystem(s), each subsystem consisting of two batteries, one battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE to support required trains of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems—Shutdown." The EDG DC system, consisting of a battery, battery charger, and the corresponding control equipment and interconnection cabling for the EDG, are required to be OPERABLE to support the EDG required by LCO 3.8.2, "AC Sources—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 recently irradiated fuel).

APPLICABILITY

The DC electrical power sources and EDG DC system required to be OPERABLE in MODES 5 and 6, and during movement of recently irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the recently irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 300 hours) are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power and EDG DC system requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

BASES

ACTIONS

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

The train with DC power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and recently irradiated fuel movement. 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 recently irradiated 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 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 subsystems 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 subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

BASES

ACTIONS (continued)	B.1 With the required EDG's DC system inoperable, the EDG is not OPERABLE and the applicable Conditions and Required Actions of LCO 3.8.2, "AC Sources—Shutdown," must be entered immediately.
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 3.8.4.9. 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 required OPERABLE DC sources or EDG DC system 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 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the Station and EDG batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the emergency auxiliaries, and control and switching during all MODES of operation. The EDG DC electrical power system consists of the battery, battery charger, and interconnecting cabling supplying power to the associated EDG components to supply the required DC voltage to allow the EDG to perform the required safety function.

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 cell parameters satisfy the Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.

BASES

APPLICABILITY

The battery cell parameters are required solely for the support of the associated DC electrical power subsystem(s) and EDG DC system(s). Therefore, the battery is only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With one or more cells in one or more batteries not within limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1 in the accompanying LCO, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met and operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check will provide a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A or B limits. This periodic verification is consistent with the normal Frequency of pilot cell Surveillances.

(continued)

BASES

ACTIONS

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

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. With the consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable prior to declaring the battery inoperable.

B.1

With one or more batteries with one or more battery cell parameters outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem or EDG DC system must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below 60°F for the Station batteries, are also cause for immediately declaring the associated DC electrical power subsystem inoperable. Representative cells will consist of at least 10 cells.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 3), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte level of pilot cells. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.2

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. In addition, within 24 hours of a battery discharge < 110 V or a battery overcharge > 150 V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ 110 V, do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.2 (continued)

consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells of the Station batteries is > 60°F, is consistent with a recommendation of IEEE-450 (Ref. 3). The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer recommendations.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose level, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendations of IEEE-450 (Ref. 3), which states that prolonged operation of cells < 2.13 V can reduce the life expectancy of cells.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.200 (0.015 below the manufacturer fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 3), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturer fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell will not mask overall degradation of the battery.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category C limits specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limits for float voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ≥ 1.195 is based on manufacturer recommendations (0.020 below the manufacturer recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

The footnotes to Table 3.8.6-1 are applicable to Category A, B, and C specific gravity. Footnote (b) to Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when Station battery charging current is < 2 amps on float charge. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a Station battery recharge. Within 7 days, each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

BASES

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.
3. IEEE-450-1980.

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters—Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the vital buses. The inverters can be powered from a battery charger or from the station battery. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Trip System (RTS) 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 Chapter 15 (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RTS 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 from a battery charger 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 its associated battery for ≤ 24 hours, if the vital bus is powered from a constant voltage transformer and all other inverters are OPERABLE. This allows an equalizing charge to be placed on the associated battery. If the inverters were not disconnected, the resulting voltage condition might damage the inverters. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 24 hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected AC vital bus while 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 those inverters associated with the single battery undergoing an equalizing charge may be disconnected. All other inverters must be aligned to their associated batteries, regardless of the number of inverters or unit design.

BASES

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

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 constant voltage source transformer.

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 7 days to fix the inoperable inverter and return it to service. The 7 day limit is based upon a risk evaluation, 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 its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices.

The following compensatory measures will be implemented when an instrument bus inverter is unavailable:

a. Entry into Condition A will not be planned concurrent with EDG maintenance, and

(continued)

BASES

ACTIONS

A.1 (continued)

b. Entry into Condition A will not be planned concurrent with planned maintenance on another RPS/ESFAS channel that results in that channel being in a tripped condition.

B.1

With one or more required LCO 3.8.7.b inverters inoperable, the reliability of the shared component(s) on the other unit is degraded. In this condition, the associated shared component is declared inoperable within 7 days. Service Water, Main Control Room/Emergency Switchgear Room Emergency Ventilation System, and Component Cooling Water are shared systems.

C.1 and C.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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation of the RTS and ESFAS connected to the AC vital buses. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 8.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.

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 Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Trip 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 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 recently irradiated fuel. Due to radioactive decay, the inverter(s) are only required to mitigate fuel handling accidents involving handling recently irradiated fuel. (i.e., fuel that has occupied part of a critical core within a time frame established by analysis. The term recently is defined as all irradiated fuel assemblies, until analysis is performed to determine a specific time frame.)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 required inverter(s) 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 battery powered inverters provide uninterruptible supply of AC electrical power to the AC vital buses even if the 4.16 kV safety buses are de-energized. OPERABILITY of the inverters requires 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 recently irradiated fuel). Supported system(s) that do not provide automatic function(s) may be connected to a vital bus that is powered by a constant voltage transformer (example: Low Temperature Overpressure Protection, when not in automatic).
APPLICABILITY	The inverters required to be OPERABLE in MODES 5 and 6 and during movement of recently irradiated 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 recently irradiated fuel (i.e., fuel that has occupied part of a critical core within the previous 300 hours) are available; c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and d. Instrumentation and control capability is available for monitoring and maintaining the 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.

BASES

ACTIONS

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

The required OPERABLE Inverters are capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, recently irradiated 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 recently irradiated 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 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.

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 emergency diesel generator (EDG) source. Unit 1 and Unit 2 each have a normal offsite source and an alternate offsite source. Transfer to the alternate offsite source is a manual operation. In the event of a loss of offsite power, the EDGs for the affected buses will start and load. The EDGs for Unit 1 and Unit 2 will continue to run until (a) the safety bus is transferred to the alternate offsite source, or (b) the normal offsite source is restored. If offsite sources are unavailable, the onsite EDG supplies power to the 4.16 kV ESF bus. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources—Operating," and the Bases for LCO 3.8.4, "DC Sources—Operating."

The secondary 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 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.

There are two independent 125 VDC electrical power distribution subsystems for each train.

(continued)

BASES

BACKGROUND (continued)

For the other unit, one AC and DC bus on that unit is needed to support operation of each required Service Water (SW) pump, Main Control Room (MCR)/Emergency Switchgear Room (ESGR) Emergency Ventilation System (EVS) fan, Auxiliary Building central exhaust fan, and Component Cooling Water (CC) pump. SW, MCR/ESGR EVS, and CC are shared systems.

Two trains of electrical circuits on the AC Vital buses provide power to the Auxiliary Building Central exhaust subsystem filter and bypass dampers. One circuit is associated with the manual control switch on the Unit 1 ventilation Panel is powered from the Vital Bus 1-I. The other circuit is associated with the manual control switch on the Unit 2 Ventilation Panel is powered from Vital Bus 2-III. Either circuit will realign all associated dampers to the filter position. Vital power is not required as the system is aligned to operate the dampers to the filter (accident) position upon loss of power.

The list of all required distribution buses is presented in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1), and in the UFSAR, Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the 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.

BASES

The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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 H and Train J 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 proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage, or constant voltage transformer.

In addition, tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, 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.

BASES

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 LCO 3.8.9.a AC electrical power distribution subsystem(s) inoperable, the minimum safety functions can still be accomplished, assuming no single failure, as long as one set of redundant required equipment (AC buses and load centers) supporting each safety function remains energized to their proper voltages. Redundant required equipment is listed in Table B 3.8.9-1. 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 offsite power to the train and the associated EDG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit 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

ACTIONS

A.1 (continued)

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 train(s) made inoperable power distribution subsystem(s). 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 appropriate attention is given to restoring charging power to batteries, if necessary, after loss of distribution systems.

B.1

With one or more LCO 3.8.9.a 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

BASES

ACTIONS

B.1 (continued)

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, or 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.

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

BASES

ACTIONS

B.1 (continued)

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 LCO 3.8.9.a 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 DC bus(es) must be restored to OPERABLE status within 2 hours by powering the bus(es) 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.

ACTIONS

C.1 (continued)

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:

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.

BASES

ACTIONS

D.1

With one or more required LCO 3.8.9.b AC electrical power distribution subsystem(s) inoperable, the shared component(s) on the other unit is not capable of operating. In this condition, the associated shared component is declared inoperable immediately. SW, MCR/ESGR EVS, and CC are shared systems. The associated Conditions or Required Actions of LCO 3.7.8, "Service Water System," LCO 3.7.10, "MCR/ESGR Emergency Ventilation System," and LCO 3.7.19, "Component Cooling Water (CC) System," are followed.

E.1

With one or more required LCO 3.8.9.b DC electrical power distribution subsystem(s) inoperable, the shared component(s) on the other unit is not capable of operating. In this condition, the associated shared component is declared inoperable immediately. SW, MCR/ESGR EVS, and CC are shared systems. The associated Conditions or Required Actions of LCO 3.7.8, 3.7.10, 3.7.12, and 3.7.19 are followed.

F.1

With one or more required LCO 3.8.9.b AC vital electrical power distribution subsystem(s) inoperable, the shared component(s) on the other unit is not capable of operating. In this condition, the associated shared component is declared inoperable immediately. SW, MCR/ESGR EVS, and CC are shared systems.

G.1 and G.2

If the inoperable LCO 3.8.9.a 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 unit systems.

BASES

ACTIONS

H.1

Condition H 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 LCO 3.8.9.a electrical power distribution subsystem results in the loss of a required function, the unit 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 proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. Verification of proper voltage availability for 480 volt buses and load centers may be performed by indirect methods. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

3. Regulatory Guide 1.93, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

		TRAIN H*		TRAIN J*	
TYPE	VOLTAGE	Unit 1	Unit 2	Unit 1	Unit 2
AC emergency buses	4160 V	ESF Bus		ESF Bus	
		1H	2H	1J	2J
	480 V	Load Centers		Load Centers	
		1H	2H	1J	2J
		1H1	2H1	1J1	2J1
DC buses	125 V	Bus 1-I	2-I	Bus 1-III	2-III
		Bus 1-II	2-II	Bus 1-IV	2-IV
AC vital buses	120 V	Bus 1-1	2-1	Bus 1-3	2-3
		Bus 1-2	2-2	Bus 1-4	2-4

* Each train of the AC and DC electrical power distribution systems is a subsystem.

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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 Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power distribution subsystems during MODES 5 and 6, and during movement of recently irradiated fuel assemblies 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 provided to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, the 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 core within a time frame established by analysis. The term recently is defined as all irradiated fuel assemblies, until analysis is performed to determine a specific time frame.)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific unit 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 recently irradiated fuel).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of recently irradiated 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 recently irradiated fuel (i.e., fuel that has occupied part of a critical core within the previous 300 hours) are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the 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.

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant 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 recently irradiated fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies, 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.2.4 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.

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

Therefore, Required Action A.2.5 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.

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 buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. Verification of proper voltage availability for 480 volt buses and load centers may be performed by indirect methods. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

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 in order to maintain 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 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 to form 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

(continued)

BASES

BACKGROUND (continued)	refueling (see LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level," and LCO 3.9.6, "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.
APPLICABLE SAFETY ANALYSES	During refueling operations, the reactivity condition of the core is established to protect against inadvertent positive reactivity addition and 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 ≤ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ 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 ≤ 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,

(continued)

BASES

APPLICABILITY (continued)

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 refueling cavity when those volumes are connected to the RCS. When the refueling canal and refueling cavity are isolated from the RCS, no potential path for boron dilution exists.

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.

(continued)

BASES

ACTIONS	A.3 (continued) 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 re-connecting 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. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 3.1.22.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Primary Grade Water Flow Path Isolation Valves—MODE 6

BASES

BACKGROUND

During MODE 6 operations, the isolation valves for primary grade water flow paths that are connected to the Reactor Coolant System (RCS) must be closed to prevent unplanned boron dilution of the reactor coolant. The isolation valves must be locked, sealed or otherwise secured in the closed position.

The Chemical and Volume Control System is capable of supplying borated and unborated water to the RCS through various flow paths. Since a positive reactivity addition made by uncontrolled reduction of the boron concentration is inappropriate during MODE 6, isolation of all primary grade water flow paths prevents an unplanned boron dilution.

APPLICABLE SAFETY ANALYSES

The possibility of an inadvertent boron dilution event (Ref. 1) occurring during MODE 6 refueling operations is precluded by adherence to this LCO, which requires that primary grade water flow paths be isolated. Closing the required valves during refueling operations prevents the flow of unborated water to the filled portion of the RCS. The valves are used to isolate primary grade water flow paths. These valves have the potential to indirectly allow dilution of the RCS boron concentration in MODE 6. By isolating primary grade water flow paths, a safety analysis for an uncontrolled boron dilution accident is not required for MODE 6.

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

LCO

This LCO requires that flow paths to the RCS from primary grade water sources be isolated to prevent unplanned boron dilution during MODE 6 and thus avoid a reduction in SDM.

For Unit 1, primary grade water flow paths may be isolated from the RCS by closing valve 1-CH-217. Alternatively, 1-CH-220, 1-CH-241, 1-CH-FCV-1114B and 1-CH-FCV-1113B may be used in lieu of 1-CH-217. For Unit 2, primary grade water

(continued)

BASES

LCO (continued)

flow paths may be isolated from the RCS by closing valve 2-CH-140. Alternatively, 2-CH-160, 2-CH-156, 2-CH-FCV-2114B, and 2-CH-FCV-2113B may be used in lieu of 2-CH-140.

The LCO is modified by a Note which allows the primary grade water flow path isolation valves to be opened under administrative control for planned boron dilution or makeup activities.

APPLICABILITY

In MODE 6, this LCO is applicable to prevent an inadvertent boron dilution event by ensuring isolation of primary grade water flow paths to the RCS.

In MODES 3, 4, and 5, LCO 3.1.8, Primary Grade Water Flow Path Isolation Valves, requires the primary grade water flow paths to the RCS to be isolated to prevent an inadvertent boron dilution.

In MODES 1 and 2, the boron dilution accident was analyzed and was found to be capable of being mitigated.

ACTIONS

A.1

Continuation of CORE ALTERATIONS is contingent upon maintaining the unit in compliance with this LCO. With any valve used to isolate primary grade water flow paths not locked, sealed or otherwise secured in the closed position, all operations involving CORE ALTERATIONS 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 primary grade water flow path isolation valves secured closed. Locking, sealing, or securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of 15 minutes provides sufficient time to close, lock, seal, or otherwise secure the flow path isolation valve.

BASES

ACTIONS (continued)

A.3

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

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valves are to be locked, sealed, or otherwise secured closed to isolate possible dilution paths. The likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote due to the large mass of borated water in the refueling cavity and the fact that the primary grade water flow paths are isolated, precluding a dilution. The boron concentration is checked during MODE 6 under SR 3.9.1.1. The Frequency is based on verifying that the isolation valves are locked, sealed, or otherwise secured within 15 minutes following a boron dilution or makeup activity. This Frequency is based on engineering judgment and is considered reasonable in view of other administrative controls that will ensure that the valve opening is an unlikely possibility.

REFERENCES

1. UFSAR, Section 15.2.4.

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B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed 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 installed source range neutron flux monitors are BF3 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 and an audible alarm in the control room to alert operators to a possible dilution accident. The NIS is designed in accordance with the criteria presented in Reference 1.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2). The need for a safety analysis for an uncontrolled boron dilution accident is eliminated by isolating all unborated water sources as required by LCO 3.9.2, "Primary Grade Water Flow Path Isolation Valves—MODE 6."

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.

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, these same installed source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) 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 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 operations. 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, 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.

(continued)

BASES

ACTIONS

B.2 (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 3.9.3.1

SR 3.9.3.1 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.9.3.2

SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 3.

2. UFSAR, Chapter 15.

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B 3.9 REFUELING OPERATIONS

B 3.9.4 Containment Penetrations

BASES

BACKGROUND

During movement of 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, this 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 Regulatory Guide 1.183 (Ref. 2). 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 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." One of the containment air locks is an integral part of the containment equipment hatch. During refueling the air lock

(continued)

BASES

BACKGROUND (continued)

that is part of the containment equipment hatch is typically replaced by a temporary hatch plate. While the temporary hatch plate is installed, there is only one air lock by which to enter containment. The LCO only applies to containment air locks that are installed. 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 within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed.

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from the containment due to a fuel handling accident involving handling of recently irradiated fuel.

The Containment Purge and Exhaust System includes a 36 inch purge penetration and a 36 inch exhaust penetration. During MODES 1, 2, 3, and 4, the two valves in each of the purge and exhaust flow paths are secured in the closed position. The Containment Purge and Exhaust System is not subject to a Specification in MODE 5.

In MODE 6, large air exchanges are necessary to conduct refueling operations. The 36 inch purge system is used for this purpose.

The 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. Equivalent isolation methods must be approved 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.

BASES

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident involving handling recently irradiated fuel. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 1). Fuel handling accidents, analyzed in Reference 2, involve dropping a single irradiated fuel assembly and handling tool. The requirements of LCO 3.9.7, "Refueling Cavity Water Level," in conjunction with a minimum decay time of 100 hours prior to movement of irradiated fuel (i.e., fuel that has not been recently irradiated) without containment closure capability ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are within the guideline values specified in Regulatory Guide 1.183 (Ref. 2).

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. For the OPERABLE containment purge and exhaust penetrations, this LCO ensures that these penetrations are isolable by a containment purge and exhaust isolation valve.

The LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during movement of recently irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident.

APPLICABILITY

The containment penetration requirements are applicable during movement of 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,

(continued)

BASES

APPLICABILITY (continued)	and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when movement of irradiated fuel assemblies within containment is not being conducted, the potential for a design basis fuel handling accident does not exist. Additionally, due to radioactive decay, containment closure capability is only required during a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). A fuel handling accident involving fuel with a minimum decay time of 100 hours prior to movement will result in doses that are within the guideline values specified in Regulatory Guide 1.183 (Ref. 2) even without containment closure capability. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1

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 Containment Purge and Exhaust Isolation System not capable of manual actuation when the purge and exhaust valves are open, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending movement of 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 3.9.4.1

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 purge and exhaust valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being manually closed.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.2

This Surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. This Surveillance will ensure that the valves are capable of being closed after a postulated fuel handling accident involving handling recently irradiated fuel to limit a release of fission product radioactivity from the containment. The SR is modified by a Note stating 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 manual initiation capability.

REFERENCES

1. UFSAR, Section 15.4.7.

2. Regulatory Guide 1.183, July 2000.

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B 3.9 REFUELING OPERATIONS

B 3.9.5 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) 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 removal of the RHR loop from operation for short durations, under the condition that the boron concentration is not diluted. This conditional removal from operation of the RHR loop 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

(continued)

BASES

LCO (continued)

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.

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 RHR discharge temperature. The flow path starts in one of the RCS hot legs and is returned to at least one of the RCS cold legs.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from operation for up to 1 hour per 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration by 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. This 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. During this 1 hour period, 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 3.9.7, "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 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level."

BASES

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note 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 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 LCO 3.9.5 is not met, the following actions must be taken:

a. the equipment hatch or equipment hatch cover must be closed and secured with at least four bolts;

b. one door in each installed air lock must be closed; and

(continued)

BASES

ACTIONS

A.4, A.5, A.6.1, and A.6.2 (continued)

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.

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.

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 demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 5.5.4.

B 3.9 REFUELING OPERATIONS

B 3.9.6 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) 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;

(continued)

BASES

LCO (continued)

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. 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°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 unit 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 RHR discharge temperature. The flow path starts in one of the RCS hot legs and is returned to at least one of the RCS cold legs.

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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level."

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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 3.9.5, 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. Reduced boron concentrations cannot occur by the addition of water with a lower boron concentration than that contained in the RCS, because all of the unborated water sources are isolated.

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 or equipment hatch cover must be closed and secured with at least 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.

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

(continued)

BASES

ACTIONS

B.3, B.4, B.5.1, and B.5.2 (continued)

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 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. In addition, during operation of the RHR loop with the water level lowered to the level of the reactor vessel nozzles, the RHR pump net positive suction head requirements must be met. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.9.6.2

Verification that the 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 the required pump. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

The 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. UFSAR, Section 5.5.4.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of 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 containment, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to the limits of Regulatory Guide 1.183.

APPLICABLE SAFETY ANALYSES

During movement of 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 an effective iodine decontamination factor of 200 (Appendix B Assumption 2 of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99.5% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 8% of the fuel rod I-131 inventory and 5% of all other iodine isotopes, which are included as other halogens (Ref. 1).

The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft, 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 are maintained within allowable limits (Ref. 1).

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.

BASES

APPLICABILITY	LCO 3.9.7 is applicable when moving 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 3.7.16, "Fuel Storage Pool Water Level."
ACTIONS	A.1 With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of 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 3.9.7.1 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 based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. Regulatory Guide 1.183, July 2000. 2. UFSAR, Section 15.4.7.