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PG&E Letter DCL-24-106

U.S. Nuclear Regulatory Commission
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10 CFR 50.71(e)

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Power Plant Units 1 and 2
Technical Specification Bases, Revision 15

Dear Commissioners and Staff:

Pursuant to Diablo Canyon Power Plant (DCPP) Unit 1 and Unit 2 Technical Specification (TS) 5.5.14, "Technical Specifications (TS) Bases Control Program," Pacific Gas and Electric Company (PG&E) hereby submits Revision 15 of the DCPP TS Bases. Revision 15 includes changes made to the DCPP TS Bases from April 1, 2023, through September 30, 2024, and replaces Revision 14 in its entirety. Changes are noted by revision bars in the right margin of the affected TS Bases.

The enclosure to this letter contains DCPP TS Bases, Revision 15.

PG&E makes no new or revised regulatory commitments (as defined by NEI 99-04) in this letter.

If you have any questions or require additional information, please contact me at (805) 545-4609.

Sincerely,

J. R. M.

James R. Morris

11-18-2024
Date

rntt/50946118
Enclosure
cc: Diablo Distribution

cc/enc: Mahdi O. Hayes, NRC Senior Resident Inspector
Samson S. Lee, NRC Senior Project Manager
John D. Monninger, NRC Region IV Administrator

Diablo Canyon - Units 1 and 2
Technical Specification Bases
Revision 15
October 2024

(Revision 15 replaces Revision 14 in its entirety)

Pacific Gas and Electric Company®

Diablo Canyon Power Plant Units 1 and 2

Technical Specification Bases

Revision 15

October 2024

Docket No. 50-275 Docket No. 50-323

(continued)

(continued)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10, 1971 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

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

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

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

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

(continued)

BASES (continued)

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 setpoints (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 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.

Protection for these reactor core SLs is provided by the steam generator safety valves and the following automatic reactor trip functions:

a. High pressurizer pressure trip;

b. Low pressurizer pressure trip;

c. Overtemperature Δ T trip;

d. Overpower Δ T trip;

e. Power Range Neutron Flux trip

The limitation that the average enthalpy in the hot leg be less than or equal to the enthalpy of saturated liquid also ensures that the Δ T measured by instrumentation, used in the RPS design as a measure of core power, is proportional to core power.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the UFSAR, Ref. 5) provide more restrictive limits to ensure that the SLs are not exceeded.

(continued)

BASES (continued)

SAFETY LIMITS	The safety limit is based upon the loci of points of THERMAL POWER, RCS pressure, and average temperature below which the calculated DNBR is not less than the design DNBR value, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the exit quality is within the limits defined by the DNBR correlation. The curves are based on enthalpy rise hot channel factor limits provided in the COLR. The SL is higher than the limit calculated when the AFD is within the limits of the $F_1(\Delta I)$ function of the overtemperature ΔT reactor trip. When the AFD is not within the tolerance, the AFD effect on the overtemperature ΔT reactor trips will reduce the setpoints to provide protection consistent with the reactor core SLs (Refs. 3 and 4).
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 steam generator 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. Setpoints 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.
SAFETY LIMIT VIOLATIONS	The following SL violation responses are applicable to the reactor core SLs. If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable. The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 10, 1971 2. UFSAR, Section 7.2 3. WCAP-8746-A, March 1977 4. WCAP-9273-NP-A, July 1985 5. UFSAR, Chapter 15

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 9, 1967, “Reactor Coolant Pressure Boundary,” 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, 1971, "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 were hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 50.67, "Accident Source Term" (Ref. 4) .

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded. The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the Safety valves on the secondary side are assumed to open when the steam pressure reaches the safety valve settings. Main feedwater supply is lost at the time of turbine trip. The Reactor Trip System setpoints (Ref. 5), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices. More specifically, no credit is taken for operation of the following: a. Pressurizer power operated relief valves (PORVs); b. Steam line relief valve; 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.

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BASES (continued)

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, or the reactor vessel is sufficiently vented, 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, "Accident Source Term," limits (Ref. 4) . The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized. If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 9, 1967 and GDC 28, 1971 (associated with 1967 GDC 32 per UFSAR Appendix 3.1A) 2. ASME, Boiler and Pressure Vessel Code, Section III, Summer 1969 3. ASME, Boiler and Pressure Vessel Code, Section XI 4. 10 CFR 50.67 5. UFSAR, Section 7.2 6. DCM S-7, 3.4.1

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.8 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not 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

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BASES

LCO 3.0.2 (continued)	individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits." The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed. When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.
LCO 3.0.3	LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and: 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

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BASES

LCO 3.0.3 (continued)

maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

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

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

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

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.

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BASES

LCO 3.0.3 (continued)	In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken. Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.15, "Fuel Storage Pool Water Level." LCO 3.7.15 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.15 are not met while in MODE 1, 2, 3, or 4, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.15 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 allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c. LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions. LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

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BASES

LCO 3.0.4 (continued)

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

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

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

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BASES

LCO 3.0.4 (continued)

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

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

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

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that results from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, MODE 4 to MODE 5, and MODE 5 to MODE 6.

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BASES

LCO 3.0.4 (continued)

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

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

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BASES (continued)

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; <u>OR</u> b. The OPERABILITY of other equipment.) The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance. An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing. 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

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BASES

LCO 3.0.6 (continued)	do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions. However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2. Specification 5.5.15, "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. 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.
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 LCO 3.1.8, allows specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be 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

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BASES

LCO 3.0.7 (continued)	be changed to perform the special test or operation will remain in effect. The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.
LCO 3.0.8	LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee. If 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.

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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. 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.

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.
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 for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have 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

(continued)

BASES

SR 3.0.1 (continued)	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 plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities). The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Therefore, when a test interval is specified in the regulations, the interval cannot be extended by the TS, and the SR include a Note in the Frequency stating, "SR 3.0.2 is not applicable." An example of an exception when the test interval is not specified in the regulations is the Note in the Containment Leakage Rate Testing Program, "SR 3.0.2 is not applicable." This exception is provided because the program already includes extension of test interval. 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

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BASES

SR 3.0.2 (continued)	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. SR 3.0.3 is only acceptable if it is discovered that a Surveillance was not performed after the specified Frequency had already expired. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance. The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering 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.

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BASES

SR 3.0.3 (continued)

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

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

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BASES (continued)

SR 3.0.4

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

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

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

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided that requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, MODE 4 to MODE 5, and MODE 5 to MODE 6.

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BASES

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

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND	According to GDC 26, 1971 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel. SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion 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 Chemical and Volume Control System can control the soluble boron concentration to compensate for fuel depletion during operation and all xenon burnout reactivity changes and can maintain the reactor subcritical under cold conditions. During power operation, SDM control is ensured, assuming that core reactivity is within design limit of LCO 3.1.2, 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.
APPLICABLE SAFETY ANALYSIS	The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis 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. For MODE 5, the primary safety analysis that

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

relies on the SDM limits is the boron dilution analysis.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are not exceeded. 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 ≤ 200 cal/gm average fuel pellet enthalpy at the hot spot in irradiated fuel for the rod ejection accident, Ref. 5); and

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

The most limiting accidents for the SDM requirements are the main steam line break (MSLB) and inadvertent boron dilution accidents, as described in the UFSAR (Refs. 2 and 3). In addition to the limiting MSLB transient, the SDM requirement is also used in the analyses of the following events:

a. Inadvertent boron dilution;

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

c. Start of an inactive reactor coolant pump (RCP); and

d. Rod ejection.

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 with RCS T_{avg} equal to 547°F. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

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BASES

APPLICABLE SAFETY ANALYSIS (continued)	In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest. Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high power level trip or a high pressurizer pressure trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits. The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power. The startup of an inactive RCP in MODES 1 or 2 is precluded. In MODE 3, the startup of an inactive RCP cannot result in a "cold water" criticality, even if the maximum difference in temperature exists between the SG and the core. The maximum positive reactivity addition that can occur due to an inadvertent start is less than half the minimum required SDM. Startup of an idle RCP cannot, therefore, produce a return to power from the hot standby condition. SDM satisfies Criterion 2 of 10CFR50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.
LCO	SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration. The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 50.67, "Accident Source Term," limits (Ref. 4) . For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be sufficient. The required SDM is specified in the COLR.

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BASES (continued)

APPLICABILITY

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

ACTIONS

A.1

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

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

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

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

In MODES 2 (with k_{eff} <1.0), 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects (SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth):

a. RCS boron concentration;
b. Control and shutdown rod 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).

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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 10 CFR 50, Appendix A, GDC 26, 1971 2 UFSAR, Section 15.4.2.1 3 UFSAR, Section 15.2.4 4 10 CFR 50.67 5 UFSAR, Section 15.4.6.1.6.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, 1971; GDC 28, 1971; and GDC 29, 1971 (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.

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

(continued)

BASES

BACKGROUND (continued)	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 plant operation is maintained within the assumptions of the safety analyses. Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity. Design calculations 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 as well as providing inputs to the safety analysis. The comparison between measured and predicted initial core reactivity provides a validation of the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	burnups beyond BOC, or that an unexpected change in core conditions has occurred. The normalization of predicted RCS boron concentration to the measured value when deemed necessary shall be 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 10CFR50.36(c)(2)(ii).
LCO	Long term core reactivity behavior is a result of the core physics design and cannot be easily altered 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 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.

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BASES

APPLICABILITY (continued)

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. Core reactivity and control rod worth measurements are 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 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 and the boron concentration requirement for SDM may be renormalized and power operation may continue. If operational restrictions 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.

(continued)

BASES

ACTIONS (continued)	B.1 If the core reactivity cannot be restored to within the 1% Δk/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by LCO 3.1.1 Required Action A.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.
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 the normalization (adjustment, only if necessary) of predicted core reactivity to the 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. 10 CFR 50, Appendix A, GDC 26, 1971; GDC 28, 1971; and GDC 29, 1971 2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11, 1971 (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 surveillances. Reload cores are designed so that the beginning of cycle (BOC) MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOC limit.

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

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

(continued)

BASES

BACKGROUND (continued)	The SRs for verification 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 (Ref. 2) 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 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 verification is conducted at conditions when the RCS boron concentration reaches a boron concentration equivalent to 300 ppm at an equilibrium, all rods out, RTP condition. The value determined during the Surveillance may be extrapolated to project the EOC value, in order to confirm reload design predictions.

The most negative MTC value, equivalent to the most positive moderator density coefficient (MDC), was obtained by incrementally

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	correcting the MDC used in the UFSAR analyses to nominal operating conditions. These corrections involved: (1) a conversion of the MDC used in the UFSAR accident analyses to its equivalent MTC, based on the rate of change of moderator density with temperature at RATED THERMAL POWER conditions, and (2) adding margin to this value to account for the largest difference in MTC observed between an EOC, all rods withdrawn, RATED THERMAL POWER condition and an envelope of those most adverse conditions of moderator temperature and pressure, rods inserted to their insertion limits, axial power skewing, and xenon concentration that can occur in normal operation within Technical Specification limits and lead to a significantly more negative EOC MTC at RATED THERMAL POWER. These corrections transformed the MDC value used in the UFSAR accident analyses into the limiting EOC MTC value. The 300 ppm surveillance limit MTC value represents a conservative value (with corrections for burnup and soluble boron) at a core condition of 300 ppm equilibrium boron concentration and is obtained by adding an allowance for burnup and soluble boron concentration changes to the limiting EOC MTC value. MTC satisfies Criterion 2 of 10CFR50.36(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 near BOC when core reactivity and required boron concentration are at their maximum values; this upper bound must not be exceeded. This maximum upper limit is evaluated near 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. The conditions of the LCO are ensured through surveillances. 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.

(continued)

BASES

LCO (continued)	The LCO establishes a maximum positive value that cannot be exceeded. The BOC positive limit and the EOC negative 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.
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	<u>A.1</u> 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 surveillance 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. <u>B.1</u> If the required administrative withdrawal limits are not established within 24 hours, the unit must be brought to MODE 2 with k_{eff} < 1.0 to prevent operation with an MTC that is more positive than that assumed in safety analyses. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)	<u>C.1</u> Exceeding the EOC MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the EOC MTC limit is exceeded, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.1.3.1</u> This SR requires verification of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the BOC limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels. If required, the BOL MTC can be used to establish administrative withdrawal limits for control banks. <u>SR 3.1.3.2</u> In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOC full power conditions. This surveillance 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 value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOC LCO limit. The 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

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BASES

SURVEILLANCE REQUIREMENTS	SR 3.1.3.2 (continued) SR 3.1.3.2 is modified by three Notes that include the following requirements: 1. The SR is required to be performed once each cycle within 7 effective full power days (EFPDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. 2. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 EFPD is sufficient to avoid exceeding the EOC limit. 3. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is less negative than the 60 ppm Surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 11, 1971 2. UFSAR, Chapter 15 3. WCAP-9273-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

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

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, 1971, "Reactor Design," GDC 26, 1971, "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 rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment 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 four control banks and four shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously and are moved in a staggered fashion, but always within one step of each other. All control banks contain two rod groups. Two shutdown banks (A and B) contain two rod groups and the remaining two shutdown banks (C and D) contain one rod group.

(continued)

BASES

BACKGROUND (continued)

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 Digital Rod Position Indication (DRPI) 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 DRPI System provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one data system fails, the DRPI will go on half accuracy. The DRPI system is capable of monitoring rod position within at least ± 12 steps with either full accuracy or half accuracy.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS

Control 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 control or shutdown 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. 3). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from bank D 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. 4).

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

Continued operation of the reactor with a misaligned rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod

(continued)

BASES

APPLICABLE ANALYSIS (continued)

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 core power distribution measurement information. 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 10CFR50.36(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 OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The 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 time assumed in the safety analyses. Rod control malfunctions that result in the inability to move a rod (e.g., rod lift coil failures), but do not impact trippability, do not necessarily result in rod inoperability.

The requirement to maintain the rod alignment to within plus or minus 12 steps of their group step counter demand position 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.

The requirement to maintain rod alignment is met by comparing individual rod DRPI indication and bank demand position indication to be within plus or minus 12 steps. If one of these position indicators become inoperable, the conditions of this LCO are still met by compliance with LCO 3.1.7.

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 (continued)

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 plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are typically fully inserted 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. Refer to LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 2 with k_{eff} <1.0, 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, 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.

With an inoperable rod(s), this ACTION provides for verification of SDM, this is most simply accomplished by verifying rod insertion limits are met. Additionally, actions could include calculation of the current SDM and boration to meet limits specified in the COLR or proceed to MODE 3. These actions are consistent with those specified in LCO 3.1.5 and LCO 3.1.6.

A rod is considered trippable if it was demonstrated OPERABLE during the last performance of SR 3.1.4.2 and met the rod drop time criteria during the last performance of SR 3.1.4.3.

In this situation, SDM verification must account for the absence of the negative reactivity of the untrippable rod(s), as well as the rod of maximum worth.

A.2

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

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

(continued)

BASES

ACTIONS (continued)

B.1.1 and B.1.2

When a rod becomes misaligned, it can usually be moved and is still trippable (i.e., OPERABLE).

An alternative to realigning a single misaligned RCCA to the group demand position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits."

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

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

B.2, B.3, B.4, and B.5

For continued operation with a misaligned rod, reactor power must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible. Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 3). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

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

(continued)

BASES

ACTIONS

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6 (continued)

Verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the core power distribution measurement information 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 of UFSAR Chapter 15 are to be used to identify the appropriate design bases events requiring re-evaluation. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

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

D.1.1 and D.1.2

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

Additionally, the requirements of LCO 3.1.5, “Shutdown Bank Insertion Limits,” and LCO 3.1.6, “Control Bank Insertion Limits,” apply if the misaligned rods are not within the required insertion limits.

(continued)

BASES

ACTIONS (continued)

D.2

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

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

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that the position of individual rods is within alignment limits provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. The Surveillance Frequency is 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 which states it is not required to be performed for rods associated with an inoperable demand position indicator or an inoperable rod position indicator. The alignment limit is based on the demand position indicator which is not available if the indicator is inoperable. LCO 3.1.7, “Rod Position Indication,” provides Actions to verify the rods are in alignment when one or more rod position indicators are inoperable.

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 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 or during 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	<u>SR 3.1.4.3</u> 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 ≥ 500°F to simulate a reactor trip under actual conditions. This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 10, 1971 and GDC 26, 1971 2. 10 CFR 50.46 3. UFSAR, Section 15.2.3 4. UFSAR, Section 4.2.3.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

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

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, 1971, "Reactor Design," GDC 26, 1971, "Reactivity Control System Redundancy and Capability," GDC 28, 1971, "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 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 four control banks and four shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. All four control banks contain two rod groups. Two shutdown banks (A and B) contain two rod groups and the remaining two shutdown banks (C and D) consist of a single group. Refer to 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. 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

(continued)

BASES

BACKGROUND (continued)	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 affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSIS

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 shutdown the reactor and maintain the required SDM (refer to LCO 3.1.1, "SHUTDOWN MARGIN - (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod.

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

a. There be no violations of:

   1. Specified acceptable fuel design limits, or

   2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

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

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

(continued)

BASES

LCO	The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown bank insertion limits are defined in the COLR. The LCO is modified by a Note indicating the LCO requirement is not applicable to shutdown banks being inserted while performing SR 3.1.4.2. This SR verifies the freedom of the rods to move, and may require the shutdown bank to move below the LCO limits, which would normally violate the LCO. This Note applies to each shutdown bank as it is moved below the insertion limit to perform the SR. This Note is not applicable should a malfunction stop performance of the SR.
APPLICABILITY	The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. The applicability in MODE 2 begins at initial control bank withdrawal, during an approach to criticality, and continues throughout MODE 2, until all control bank rods are again fully inserted by reactor trip or by shutdown. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are, typically, fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 2 with k_{eff} <1.0, 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

(Continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, and A.3

If one shutdown bank is inserted less than or equal to 16 steps below the insertion limit, 24 hours is allowed to restore the shutdown bank to within the limit. This is necessary because the available SDM may be reduced with a shutdown bank not within its insertion limit. Verification of all control banks are within the insertion limits specified in the COLR is required within 1 hour. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If a shutdown bank is not within its insertion limit, SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

While the shutdown bank is outside the insertion limit, all control banks must be within their insertion limits to ensure sufficient shutdown margin is available. The 24 hour Completion Time is sufficient to repair most rod control failures that would prevent movement of a shutdown bank.

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

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

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time. Additionally, the requirements of LCO 3.1.4, “Rod Group Alignment Limits,” apply if one or more shutdown rods are not within the required alignment limits.

(continued)

BASES

ACTIONS (continued)	C.1 If the Required Actions and associated Completion Times 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 plant systems.
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. 10 CFR 50, Appendix A, GDC 10, 1971; GDC 26, 1971; and GDC 28, 1971 2. 10 CFR 50.46 3. UFSAR, Section 15.4.3.2.4.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

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

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, 1971, "Reactor Design," GDC 26, 1971, "Reactivity Control System Redundancy and Capability," GDC 28, 1971, "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 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 four control banks and four shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously and are moved in a staggered fashion, but always within one step of each other. Two shutdown banks (C and D) consist of a single group. Refer to 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. The control banks are required to be at or above the insertion limit lines.

The COLR also indicates how the control banks are moved in an overlap pattern. Overlap is the distance traveled together by two control banks. The control banks are used for precise reactivity control of the reactor. The positions of the control banks can be controlled manually, or automatically by the Rod Control System. They are capable of adding reactivity very quickly (compared to borating or diluting).

(continued)

BASES

BACKGROUND (continued)	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, “Rod Group Alignment Limits,” LCO 3.1.5, "Shutdown Bank Insertion Limits," 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)," 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 assuming LCO 3.1.2, “Core Reactivity” is met for core reactivity. Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.
APPLICABLE SAFETY ANALYSES	The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function. The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that: There be no violations of: Specified acceptable fuel design limits, or Reactor Coolant System pressure boundary integrity; and 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 and shutdown 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).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths. The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 5). The insertion limits satisfy Criterion 2 of 10CFR50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.
LCO	The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion. The LCO is modified by a Note indicating the LCO requirement is not applicable to control banks being inserted while performing SR 3.1.4.2. This SR verifies the freedom of the rods to move, and may require the control bank to move below the LCO limits, which would normally violate the LCO. This Note applies to each control bank as it is moved below the insertion limit to perform the SR. This Note is not applicable should a malfunction stop performance of the SR.
APPLICABILITY	The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

(Continued)

ACTIONS

A.1, A.2.1, A.2.2, and A.3

If Control Bank A, B, or C is inserted less than or equal to 16 steps below the insertion, sequence, or overlap limits, 24 hours is allowed to restore the control bank to within the limits. Verification of all shutdown banks are within the insertion limits specified in the COLR is required within 1 hour. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If a control bank is not within its insertion limit, SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

While the control bank is outside the insertion, sequence, or overlap limits, all shutdown banks must be within their insertion limits to ensure sufficient shutdown margin is available and that power distribution is controlled. The 24 hour Completion Time is sufficient to repair most rod control failures that would prevent movement of a control bank.

Condition A is limited to Control banks A, B, or C. The allowance is not required for Control Bank D because the full power bank insertion limit can be met during performance of the SR 3.1.4.2 control rod freedom of movement (trippability) testing.

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

When the control banks are outside the acceptable insertion limits for reasons other than Condition A, 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.

(continued)

BASES

ACTIONS

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

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 (refer to LCO 3.1.1, "SHUTDOWN MARGIN - (SDM)") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration for reasons other than Condition A, they must be restored to meet the limits. Failure of sequence or overlap support equipment does not require entering the ACTIONS as long as sequence and overlap limits are maintained.

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

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

Additionally, the requirements of LCO 3.1.4, "Rod Group Alignment Limits," apply if one or more control rods are not within the required alignment limits.

D.1

If the Required Actions cannot be completed within the associated Completion Times, the plant must be brought to MODE 3, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

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. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

The Surveillance Frequency is 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 verification of compliance with the sequence and overlap limits specified in the COLR consists of an observation that the static rod positions of those control banks not fully withdrawn from the core are within the limits specified in the COLR. Bank sequence and overlap must also be maintained during rod movement, implicit within the LCO. 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 A, GDC 10, 1971; GDC 26, 1971; and GDC 28, 1971
2. 10 CFR 50.46
3. UFSAR, Section 4.3.3.4
4. Deleted
5. WCAP-9273-A, “Westinghouse Reload Safety Evaluation Methodology,” July 1985

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13, 1971 (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.

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 rod drive mechanisms. The RCCAs are divided among four control banks and four shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

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

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,

(continued)

BASES

BACKGROUND (continued)	the step counter will still count the pulse and incorrectly reflect the position of the rod. The DRPI System provides a highly accurate indication of actual 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. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one data system fails, the DRPI will go on half accuracy. The DRPI system is capable of monitoring rod position within at least ± 12 steps with either full accuracy or half accuracy.
APPLICABLE SAFETY ANALYSIS	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 bank 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"). Rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions. The rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The rod position indicators monitor rod position, which is an initial condition of the accident.
LCO	LCO 3.1.7 specifies that the DRPI 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 DRPI System on either full accuracy or half accuracy indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits"; and b. The Bank Demand Indication System has been reset in the fully inserted position, fully withdrawn position or to the DRPI System. The 12 step agreement limit between the Bank Demand Position Indication System and the DRPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of rod bank position.

(continued)

BASES

LCO (continued)	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 DRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.
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 per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator. <u>A.1, A.2.1, and A.2.2</u> When one DRPI per group in one or more groups fails, the position of the rod may still be determined indirectly by use of the core power distribution measurement information. Core power distribution measurement information can be obtained from flux maps using the movable incore detectors, or from an OPERABLE Power Distribution Monitoring System (PDMS) (References 4 & 5). The Required Action may also be ensuring, at least once per 8 hours, that F_Q satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SDM 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.

(Continued)

BASES

ACTIONS

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

Required Action A.1 requires verification of the position of a rod with an inoperable DRPI once per 8 hours which may put excessive wear and tear on the moveable incore detector system if it is used to meet the Required Action. Required Action A.2.1 provides an alternative. Required Action A.2.1 requires verification of rod position using core power distribution measurement information every 31 EFPD, which coincides with the normal use of the system to verify core power distribution.

Required Action A.2.1 includes six distinct requirements for verification of the position of rods associated with an inoperable DRPI using core power distribution measurement information:

a. Initial verification within 8 hours of the inoperability of the DRPI;

b. Re-verification once every 31 Effective Full Power Days (EFPD) thereafter;

c. Verification within 8 hours if rod control system parameters indicate unintended rod movement. An unintended rod movement is defined as the release of the rod's stationary gripper when no action was demanded either manually or automatically from the rod control system, or a rod motion in a direction other than the direction demanded by the rod control system. Verifying that no unintended rod movement has occurred is performed by monitoring the rod control system stationary gripper coil current for indications of rod movement;

d. Verification within 8 hours if the rod with an inoperable DRPI is intentionally moved greater than 12 steps;

e. Verification prior to exceeding 50% RTP if power is reduced below 50% RTP; and

f. Verification within 8 hours of reaching 100% RTP if power is reduced to less than 100% RTP.

Should the rod with the inoperable DRPI be moved more than 12 steps, or if reactor power is changed, the position of the rod with the inoperable DRPI must be verified.

Required Action A.2.2 states that the inoperable DRPI must be restored to OPERABLE status prior to entering MODE 2 from MODE 3. The repair of the inoperable DRPI must be performed prior to returning to power operation following a shutdown.

(continued)

BASES

ACTIONS
(continued)

A.3

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 3).

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

B.1and B.2

When more than one DRPI per group in one or more groups fail, additional actions are necessary. Placing the Rod Control System in manual assures unplanned rod motion will not occur.

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 the Condition.

The inoperable DRPIs must be restored, such that a maximum of one DRPI per group is inoperable, within 24 hours. The 24 hour Allowed Outage Time provides sufficient time to troubleshoot and restore the DRPI 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 control rods has been significantly moved, the Required Action of C.1 or C.2 below is required.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one DRPI inoperable in one or more groups and the affected groups have moved greater than 24 steps in one direction since the last determination of rod position, additional actions are needed to verify the position of rods within inoperable DRPI. Within 4 hours, the position of the rods with inoperable position indication must be determined using the core power distribution measurement information to verify these rods are still properly positioned, relative to their group positions. 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 using the movable incore detectors, or other power distribution measurement methods.

D.1.1 and D.1.2

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

D.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 3). 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 plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the DRPI agrees with the demand position within 12 steps ensures that the DRPI is operating correctly. Verification at 24, 48, 120, and 228 steps withdrawn for the control and shutdown banks provides assurance that the DRPI is operating correctly over the full range of indication.

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

The Surveillance is modified by a Note which states it is not required to be met for DRPIs associated with rods that do not meet LCO 3.1.4. If a rod is known to not to be within 12 steps of the group demand position, the ACTIONS of LCO 3.1.4 provide the appropriate Actions.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13, 1971 (associated with 1967 GDCs 12, 13, 14, and 15 per UFSAR Appendix 3.1A).
2. UFSAR, Chapter 15.
3. WCAP-10216-P-A, Rev. 1A, “Relaxation of Constant Axial Offset Control and F_Q Surveillance Technical Specification,” February 1994.
4. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.
5. WCAP-12472-P-A, Addendum 4, Revision 0, "BEACON Core Monitoring and Operations Support System," September 2012

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions - MODE 2

BASES

BACKGROUND

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

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

The 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.

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.

(continued)

BASES

BACKGROUND (continued)	The PHYSICS TESTS required for reload fuel cycles in MODE 2 typically include: a. Critical Boron Concentration, b. Control Rod Worth, and c. Isothermal Temperature Coefficient (ITC). These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.
APPLICABLE SAFETY ANALYSES	The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 5). 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. Reload fuel cycle PHYSICS TESTS are performed in accordance with Technical Specification requirements, fuel vendor guidelines, and established industry practices. 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 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. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of 10 CFR 50.36(c)(2)(ii). Reference 6 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.

(continued)

BASES (continued)

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. 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 operating 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 applicable PHYSICS TESTS are performed in MODE 2 at HZP.

ACTIONS

A.1 and A.2

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

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

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

(continued)

BASES

ACTIONS (continued)

D.1

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

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

A CHANNEL OPERATIONAL TEST is required on each power range and intermediate range nuclear instrument in MODES 1 and 2 by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." SR 3.1.8.1 verifies that the above surveillances are current on all bistables, ensuring that the RTS is properly aligned to provide the required degree of core protection prior to initiation and during the performance of PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest operating 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 3.1.8.3

Verification that the THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.4

Verification that the SDM is within limits specified in the COLR ensures that, for the specific RCCA and RCS temperature manipulations performed during PHYSICS TESTS, the plant is not operating in a condition that could invalidate the safety analysis assumptions.

The SDM for physics testing during tests where traditional SDM monitoring techniques are not adequate, is determined for the most restrictive test based on design calculations. Plant conditions are monitored during these tests to verify adequate SDM.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.1.8.4 (continued) 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. Not used. 5. WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985. 6. 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 not directly measurable but is inferred from a power distribution measurement obtained with either the movable incore detector system or from an OPERABLE Power Distribution Monitoring System (PDMS) (References 3 & 4). The results of the power distribution measurement are analyzed to derive a measured value for $F_Q(Z)$. These measurements are generally taken with the core at or near equilibrium conditions.

However, because this value represents an equilibrium condition, it does not include the variations in the value of $F_Q(Z)$ that are present during nonequilibrium situations, such as load following.

To account for these possible variations, the elevation dependent measured planar radial peaking factors, $F_{XY}(Z)$, are increased by an elevation dependent factor, $[T(Z)]^{COLR}$, that accounts for the expected maximum values of the transient axial power shapes postulated to occur during RAOC operation. Thus, $[T(Z)]^{COLR}$ accounts for the worst case non-equilibrium power shapes that are expected for the assumed RAOC operating space.

(continued)

BASES

BACKGROUND (continued)	The RAOC operating space is defined as the combination of AFD and Control Bank Insertion Limits assumed in the calculation of a particular $[T(Z)]^{COLR}$ function. The $[T(Z)]^{COLR}$ factors are directly dependent on the AFD and Control Bank Insertion Limit assumptions. The COLR may contain different $[T(Z)]^{COLR}$ functions that reflect different operating space assumptions. If the limit on $F_Q(Z)$ is exceeded, a more restrictive operating space may be implemented to gain margin for future non-equilibrium operation. 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.
APPLICABLE SAFETY ANALYSES	This LCO's principal effect is to preclude core power distributions that could lead to violation of the following fuel design criterion: During a large break loss of coolant accident (LOCA), there is a high level of probability that the peak cladding temperature will not exceed 2200° F (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 LOCA 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).

LCO

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

$$F_Q(Z) \le \frac{F_Q^{RTP}}{P} K(Z) \text{ for } P > 0.5$$

$$F_Q(Z) \le \frac{F_Q^{RTP}}{0.5} K(Z) \text{ for } P \le 0.5$$

where: F_Q^{RTP} is the $F_Q(Z)$ limit at RATED THERMAL POWER (RTP) provided in the COLR,

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

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

The actual values of F_Q^{RTP} and $K(Z)$ are given in the COLR.

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

(continued)

BASES

LCO
(continued)

An $F_Q^C(Z)$ evaluation requires obtaining a power distribution measurement in MODE 1. From the incore flux map results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$. The computed heat flux hot channel factor, $F_Q^C(Z)$ is obtained by the equation:

$$F_Q^C(Z) = F_Q^M(Z)\ U_{FQ}$$

where U_{FQ} is a factor that accounts for fuel manufacturing tolerances and measurement uncertainty.

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

$= F_{XY}{}^M(Z)\ ([T(Z)]^{COLR} / P)\ A_{XY}(Z)\ R_j\ U_{FQ}$ for $P > 0.5$
$= F_{XY}{}^M(Z)\ [T(Z)]^{COLR}\ A_{XY}(Z)\ R_j\ U_{FQ} / 0.5$ for $P \leq 0.5$.

The various factors in these expressions are defined below:

$F_{XY}{}^M(Z)$ is the measured radial peaking factor at axial location Z and is equal to the value of $F_Q^M(Z)/P_M(Z)$, where $P_M(Z)$ is the measured core average axial power shape.

$[T(Z)]^{COLR}$ is the cycle and burnup dependent function, specified in the COLR, which accounts for power distribution transients encountered during nonequilibrium normal operation. $[T(Z)]^{COLR}$ functions are specified for each analyzed RAOC operating space (i.e., each unique combination of AFD limits and Control Bank Insertion Limits). The $[T(Z)]^{COLR}$ functions account for the limiting non-equilibrium axial power shapes postulated to occur during normal operation for each RAOC operating space. Limiting power shapes at both full and reduced

(continued)

BASES

LCO (continued)

power operation are considered in determining the maximum values of $[T(Z)]^{COLR}$. The $[T(Z)]^{COLR}$ functions also account for the following effects: (1) the presence of spacer grids in the fuel assembly, (2) the increase in radial peaking in rodded core planes due to the presence of control rods during non-equilibrium normal operation, (3) the increase in radial peaking that occurs during part-power operation due to reduced fuel and moderator temperatures, and (4) the increase in radial peaking due to non-equilibrium xenon effects. The $[T(Z)]^{COLR}$ functions are normally calculated assuming that the Surveillance is performed at nominal RTP conditions with all shutdown and control rods fully withdrawn, i.e., all rods out (ARO). Surveillance specific $[T(Z)]^{COLR}$ values may be generated for a given surveillance core condition.

P is the THERMAL POWER / RTP.

$A_{XY}(Z)$ is a function that adjusts the $F_Q^W(Z)$ Surveillance for differences between the reference core condition assumed in generating the $[T(Z)]^{COLR}$ function and the actual core condition that exists when the Surveillance is performed. Normally, this reference core condition is 100 percent RTP, all rods out, and equilibrium xenon. For simplicity, $A_{XY}(Z)$ may be assumed to be 1.0 as this will typically result in an accurate $F_Q^W(Z)$ Surveillance result for a Surveillance that is performed at or near the reference core condition, and an underestimation of the available margin to the F_Q limit for Surveillances that are performed at core conditions different from the reference condition. Alternatively, the $A_{XY}(Z)$ function may be calculated using the NRC approved methodology in Reference 6.

U_{FQ} is a factor that accounts for measurement uncertainty and for fuel manufacturing tolerances. R_j is a cycle and burnup dependent analytical factor specified in the COLR that accounts for potential increases in $F_Q^W(Z)$ between Surveillances. R_j values are provided for each RAOC operating space.

The $F_Q(Z)$ limits define limiting values for core power peaking that, with a high level of probability, preclude peak cladding temperatures above 2200° F during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. Violating the LCO limits for $F_Q(Z)$ could result in unacceptable consequences if a design basis event were to occur while $F_Q(Z)$ exceeds its specified limits. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required, a more restrictive RAOC operating space must be implemented, or core power limits and AFD limits must be reduced.

(continued)

BASES

LCO (continued)	If the power distribution measurements are performed at a power level less than 100% RTP, then the $F^C_Q(Z)$ and $F^W_Q(Z)$ values that would result from measurements if the core was at 100% RTP should be inferred from the available information. A comparison of these inferred values with F^{RTP}_Q assures compliance with the LCO at all power levels.
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	<u>A.1</u> Reducing THERMAL POWER by ≥1% RTP for each 1% by which $F^C_Q(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F^C_Q(Z)$ is $F^M_Q(Z)$ multiplied by factors which account for manufacturing tolerances and measurement uncertainties. $F^M_Q(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of $F^C_Q(Z)$ and would require power reductions within the 15 minutes of the $F^C_Q(Z)$ determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F^C_Q(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit. If an F_Q Surveillance is performed at 100% RTP conditions, and both $F^C_Q(Z)$ and $F^W_Q(Z)$ exceed their limits, the option to reduce the THERMAL POWER limit in accordance with Required Action B.2.1 instead of implementing a new operating space in accordance with Required Action B.1 will result in a further power reduction after Required Action A.1 has been completed. However, this further power reduction would be permitted to occur over the next 4 hours. In the event the evaluated THERMAL POWER reduction in the COLR for Required Action B.2.1 did not result in a further power reduction (for example, if both Condition A and Condition B were entered at less than 100% RTP conditions), then the THERMAL POWER level established as a result of completing Required Action A.1 will take precedence, and will establish the effective operating power level limit for the unit until both Conditions A and B are exited.

(continued)

BASES

ACTIONS (continued)

A.2

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

(continued)

BASES

ACTIONS (continued)

A.3

Reduction in the Overpower ΔT trip setpoints by ≥ 1% for each 1% that THERMAL POWER is limited below RATED THERMAL POWER by Required Action A.1 is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT setpoints initially determined by Required Action A.4 may be affected by subsequent determinations of $F_Q^c(Z)$ and would require Overpower ΔT setpoint reductions within 72 hours of the $F_Q^c(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F_Q^c(Z)$ would allow increasing the maximum allowable Overpower ΔT trip setpoints.

A.4

Verification that $F_Q^c(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions. Inherent in this action is identification of the cause of the out of limit condition, and the correction of the cause, to the extent necessary to allow safe operation at the higher power level. The allowable power level is determined by extrapolating $F_Q^c(Z)$. SR 3.2.1.1 must be satisfied prior to increasing power above the extrapolated allowable power level or restoration of any reduced Reactor Trip System setpoints.

Condition A is modified by a NOTE that requires Required Action A.4 to be performed whenever the Condition is entered prior to increasing THERMAL POWER above the limit of Required Action A.1. The Note also states that SR 3.2.1.2 is not required to be performed if this Condition is entered prior to THERMAL POWER exceeding 75% RTP after a refueling. This ensures that SR 3.2.1.1 and SR 3.2.1.2 (if required) will be performed prior to increasing THERMAL POWER above the limit of Required Action A.1, even when Condition A is exited prior to performing Required Action A.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to ensure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

(continued)

BASES

ACTIONS (continued)

B.1.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Implementing a more restrictive RAOC operating space, as specified in the COLR, within the allowed Completion Time of 4 hours will restrict the AFD such that peaking factor limits will not be exceeded during non-equilibrium normal operation. Several RAOC operating spaces, representing successively smaller AFD envelopes and, optionally shallower Control Bank Insertion Limits, may be specified in the COLR. The corresponding T(Z) functions for these operating spaces can be used to determine which RAOC operating space will result in acceptable non-equilibrium operation within the $F_Q^W(Z)$ limits.

B.1.2

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. As discussed above, Required Action B.1.1 requires that a new RAOC operating space be implemented to restore $F_Q^W(Z)$ to within its limits. Required Action B.1.2 requires that SR 3.2.1.1 and SR 3.2.1.2 be performed if control rod motion occurs as a result of implementing the new RAOC operating space in accordance with Required Action B.1.1. The performance of SR 3.2.1.1 and SR 3.2.1.2 is necessary to ensure $F_Q(Z)$ is properly evaluated after any rod motion resulting from the implementation of a new RAOC operating space in accordance with Required Action B.1.1.

(continued)

BASES

ACTIONS (continued)

B.2.1

When $F_Q^W(Z)$ exceeds it limit, Required Action B.2 may be implemented instead of Required Action B.1. Required Action B.2.1 limits THERMAL POWER to less than RATED THERMAL POWER by the amount specified in the COLR. It also requires reductions in the AFD limits by the amount specified in the COLR. This maintains an acceptable absolute power density relative to the maximum power density value assumed in the safety analyses.

If the required $F_Q^W(Z)$ margin improvement exceeds the margin improvement available from the pre-analyzed THERMAL POWER and AFD reductions provided in the COLR, then THERMAL POWER must be further reduced to less than or equal to 50% RTP. In this case, reducing THERMAL POWER to less than or equal to 50% RTP will provide additional margin in the transient F_Q by the required change in THERMAL POWER and the increase in the F_Q limit. This will ensure that the F_Q limit is met during transient operation that may occur at or below 50% RTP.

The Completion Time of 4 hours provides an acceptable time to reduce the THERMAL POWER and AFD limits in an orderly manner to preclude entering an unacceptable condition during future non-equilibrium operation. The limit on THERMAL POWER initially determined by Required Action B.2.1 may be affected by subsequent determinations of $F_Q^W(Z)$ that are not within limit and could require power reductions within 4 hours of the of the subsequent $F_Q^W(Z)$ determination, if necessary to comply with the decreased THERMAL POWER limit. In short, the 4-hour Completion Time for Required Action B.2.1 applies after each $F_Q^W(Z)$ determination.

Decreases in subsequent $F_Q^W(Z)$ measurements while in Condition B would allow increasing the THERMAL POWER limit and increasing THERMAL POWER up to this revised limit.

Required Action B.2.1 is modified by a NOTE that states Required Action B.2.4 shall be completed whenever Required Action B.2.1 is performed prior to increasing THERMAL POWER above the limit of Required Action B.2.1. Required Action B.2.4 requires the performance of SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit established by Required Action B.2.1. The Note ensures that the SRs will be performed even if Condition B may be exited prior to performing Required Action B.2.4. The performance of SR 3.2.1.1 and SR 3.2.1.2 is necessary to ensure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

(continued)

BASES

ACTIONS (continued)

B.2.1 (continued)

If an F_Q surveillance is performed at 100% RTP conditions, and both $F_Q^C(Z)$ and $F_Q^W(Z)$ exceed their limits, the option to reduce the THERMAL POWER limit in accordance with proposed Required Action B.2.1 instead of implementing a new operating space in accordance with proposed Required Action B.1, will result in a further power reduction after Required Action A.1 has been completed. However, this further power reduction would be permitted to occur over the next 4 hours. In the event the evaluated THERMAL POWER reduction in the COLR for proposed Required Action B.2.1 did not result in a further power reduction (for example, if both Condition A and Condition B were entered at less than 100% RTP conditions), then the THERMAL POWER level established as a result of completing Required Action A.1 will take precedence, and will establish the effective operating power level limit for the unit until both Conditions A and B are exited.

B.2.2

A reduction of the Power Range Neutron Flux - High trip setpoints by $\geq$ 1% for each 1% by which the maximum allowable power is reduced is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in the THERMAL POWER limit and AFD limits in accordance with Required Action B.2.1.

The maximum allowable Power Range Neutron Flux - High trip setpoints initially determined by Required Action B.2.2 may be affected by subsequent determinations of $F_Q^W(Z)$ that are not within limit and could require Power Range Neutron Flux - High trip setpoint reductions within 72 hours of the subsequent $F_Q^W(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux - High trip setpoints. In short, the 72-hour Completion Time for Required Action B.2.2 applies after each $F_Q^W(Z)$ determination. Decreases in subsequent $F_Q^W(Z)$ measurements while in Condition B would allow increasing the maximum allowable Power Range Neutron Flux - High trip setpoints.

(continued)

BASES

ACTIONS (continued)

B.2.3

Reduction in the Overpower ΔT trip setpoints value of K_4 by $\geq$ 1% for each 1% by which the maximum allowable power is reduced is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in the THERMAL POWER limit and AFD limits in accordance with the Required Action B.2.1.

The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action B.2.3 may be affected by subsequent determinations of $F_Q^W(Z)$ that are not within limit and could require Overpower ΔT trip setpoint reductions within 72 hours of the subsequent $F_Q^W(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. In short, the 72-hour Completion Time for Required Action B.2.3 applies after each $F_Q^W(Z)$ determination. Decreases in subsequent $F_Q^W(Z)$ measurements while in Condition B would allow increasing the maximum allowable Overpower ΔT trip setpoints.

B.2.4

Verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ have been restored to within limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the maximum allowable power limit imposed by Required Action B.2.1, ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

C.1

If Required Actions A.1 through A.4 or B.1 through B.2.4 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from core power distribution measurement results and $F_Q^C(Z) = F_Q^M(Z)\ U_{FQ}$ (Ref. 2). The value of U_{FQ} is determined using the formulation provided in the COLR. $F_Q^C(Z)$ is then compared to its specified limits.

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

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP (and meeting the 100% RTP $F_Q(Z)$ limit) following a refueling provides assurance that some determination of $F_Q^C(Z)$ is made prior to achieving a significant power level where peak linear heat rate could approach the limits assumed in the safety analyses.

If THERMAL POWER has been increased by ≥ 20% RTP since the initial or most recent determination of $F_Q^C(Z)$, another evaluation of this factor is required 24 hours after achieving equilibrium conditions at this higher power level to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits. Equilibrium conditions are achieved when the core is sufficiently stable at the intended operating conditions required to perform the surveillance.

The allowance of up to 24 hours after achieving equilibrium conditions at the increased THERMAL POWER level to complete the next $F_Q^C(Z)$ surveillance applies to situations where the $F_Q^C(Z)$ has already been measured at least once at a reduced THERMAL POWER level. The observed margin in the previous surveillance will provide assurance that increasing power up to the next plateau will not exceed the F_Q limit, and that the core is behaving as designed.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.1 (continued)

This Frequency condition is not intended to require verification of these parameters after every 20% increase in RTP above the THERMAL POWER at which the last verification was performed. It only requires verification after a THERMAL POWER is achieved for extended operation that is 20% higher than the THERMAL POWER at which $F_Q^C(Z)$ was last measured.

In the absence of these Frequency conditions (discussed above) it is possible to operate for the number of EFPD allowed by the Frequency without verification of $F_Q^C(Z)$.

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 (continued)

SR 3.2.1.2

Because power distribution measurements are taken either at, or near equilibrium conditions, the variations in power distribution resulting from normal operational maneuvers are not typically present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation.

The measured $F_Q(Z)$ can be determined through a synthesis of the measured planar radial peaking factors, $F_{XY}{}^M(Z)$, and the measured core average axial power shape, $P_M(Z)$. Thus, $F_Q^C(Z)$ is given by the following expression:
$F_Q^C(Z) = F_{XY}{}^M(Z)\ P_M(Z)\ U_{FQ}$.

For RAOC operation, the analytical $[T(Z)]^{COLR}$ functions, specified in the COLR for each RAOC operating space, are used together with the measured $F_{XY}(Z)$ values to estimate $F_Q(Z)$ for non-equilibrium operation within the RAOC operating space. When the $F_{XY}(Z)$ values are measured at HFP ARO conditions ($A_{XY}(Z)$ equals 1.0), $F_Q^W(Z)$ is given by the following expression:
$F_Q^W(Z) = F_{XY}{}^M(Z)\ [T(Z)]^{COLR}\ R_j\ U_{FQ}$

Non-equilibrium operation can result in significant changes to the axial power shape. To a lesser extent, non-equilibrium operation can increase the radial peaking factors, $F_{XY}(Z)$, through control rod insertion and through reduced Doppler and moderator feedback at part-power conditions. The $[T(Z)]^{COLR}$ functions quantify these effects for the range of power shapes, control rod insertion, and power levels characteristic of the operating space. Multiplying $[T(Z)]^{COLR}$ by the measured full power, un-rodded $F_{XY}{}^M(Z)$ value, and the factors that account for manufacturing and measurement uncertainties gives $F_Q^W(Z)$, the maximum total peaking factor postulated for non-equilibrium RAOC operation.

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

The $[T(Z)]^{COLR}$ functions are specified in the COLR for discrete core elevations. Flux map data are typically taken for 61 axial core elevations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.2.1.2 (continued)

$F_Q^W(Z)$ evaluations are not applicable for axial core regions, measured in percent of core height:

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

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

c. Grid plane regions, +2% inclusive, and

d. Core plane regions, within 2% of the bank demand positions of the control banks.

These regions of the core are excluded from the evaluation because of the low probability that they would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions. The excluded regions at the top and bottom of the core are specified in the COLR and are defined to ensure that the minimum margin location is adequately surveilled. A slightly smaller exclusion zone may be specified, if necessary, to include the limiting margin location in the surveilled region of the core.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

SR 3.2.1.2 requires a Surveillance of $F_Q^W(Z)$ during the initial startup following each refueling within 24 hours after exceeding 75% RTP. THERMAL POWER levels below 75% are typically non-limiting with respect to the limit for $F_Q^W(Z)$. Furthermore, startup physics testing and flux symmetry measurements, also performed at low power, provide confirmation that the core is operating as expected. This Frequency ensures that verification of $F_Q^W(Z)$ is performed prior to extended operation at power levels where the maximum permitted peak LHR could be challenged and that the first verified performance of SR 3.2.1.2 after a refueling is performed at a power level high enough to provide a high level of confidence in the accuracy of the Surveillance result.

Equilibrium conditions are achieved when the core is sufficiently stable at the intended operating conditions required to perform the Surveillance.

If a previous Surveillance of $F_Q^W(Z)$ was performed at part power conditions, SR 3.2.1.2 also requires that $F_Q^W(Z)$ be verified at power levels > 20% RTP above the THERMAL POWER of its last verification within 24 hours after achieving equilibrium conditions. This ensures that $F_Q^W(Z)$ is within its limit using radial peaking factors measured at the higher power level.

The allowance of up to 24 hours after achieving equilibrium conditions will provide a more accurate measurement of $F_Q^W(Z)$ by allowing sufficient time to achieve equilibrium conditions and obtain the power distribution measurement.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.2.1.2 (continued) In the absence of these Frequency conditions (discussed above) it is possible to operate for the number of EFPD allowed by the Frequency without verification of $F_Q^W(Z)$. 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, 1974. 2. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988. 3. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994. 4. WCAP-12472-P-A, Addendum 4, Revision 0, "BEACON Core Monitoring and Operations Support System," September 2012 5. WCAP-10216-P-A, Revision 1A, “Relaxation of Constant Axial Offset Control (and) F_Q Surveillance Technical Specification,” February 1994. 6. WCAP-17661-P-A, Revision 1, “Improved RAOC and CAOC F_Q Surveillance Technical Specifications,” February 2019.

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 normal operation, operational transients, and any transient condition arising from events of moderate frequency 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.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution measurement obtained with either the movable incore detector system or from an OPERABLE Power Distribution Monitoring System (PDMS) (Reference 4). Specifically, the results of the power distribution measurement are analyzed 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. Compliance with these LCOs, along with the LCOs governing shutdown and control rod insertion and alignment, maintains the core limits on power distribution on a continuous basis.

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. 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 large break loss of coolant accident (LOCA), there is a high level of probability that peak cladding temperature (PCT) will not exceed 2200° F;

c. During an ejected rod accident, the average fuel pellet enthalpy at the hot spot in irradiated fuel must not exceed 280 cal/gm (Ref. 1); and

d. Fuel design limits required by GDC 26, 1971 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

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 the 95/95 DNB criterion applicable to a specific DNBR correlation. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB condition.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This relationship between power and $F^N_{\Delta H}$ 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 analysis. Likewise, all transients that may be DNB limited are assumed to begin with a limiting initial $F^N_{\Delta H}$ as a function of power level defined by the $F^N_{\Delta H}$ limit equation in the COLR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and $F^N_{\Delta H}$ are analyzed in the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3). The fuel is protected in part by compliance with Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1. 6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor $F^N_{\Delta H}$," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)." $F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits. $F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR. The $F^N_{\Delta H}$ limit is representative of the coolant flow channel with the maximum enthalpy rise. This channel has the highest probability for a DNB condition. A power multiplication factor in this equation includes an additional allowance for higher radial peaking factors from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase by a cycle-dependent factor, $PF_{\Delta H}$, specified in the COLR for reduction in THERMAL POWER. If the power distribution measurements are performed at a power level less than 100% RTP, then the $F^N_{\Delta H}$ values that would result from measurements if the core was at 100% RTP should be inferred from the available information. A comparison of these inferred values with $F^{N\,RTP}_{\Delta H}$ assures compliance with the LCO at all power levels.

(continued)

BASES (continued)

APPLICABILITY

The $F_{\Delta H}^{N}$ 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.

ACTIONS

A.1.1

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

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F_{\Delta H}^{N}$ within 24 hours in accordance with SR 3.2.2.1. However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F_{\Delta H}^{N}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP; however, THERMAL POWER does not have to be reduced to comply with these requirements. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

(continued)

BASES

ACTIONS (continued)

A.1.2.1 and A.1.2.2

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

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints; however, for extended operations at the reduced power level, the reduced trip setpoints are required to protect against events involving positive reactivity excursions. This is a sensitive operation that may inadvertently actuate the Reactor Protection System.

A.2

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

(continued)

BASES

ACTIONS (continued)

A.3

Verification that $F_{\Delta H}^{N}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to exceeding the $F_{\Delta H}^{N}$ limit is identified, to the extent necessary, and corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F_{\Delta H}^{N}$ 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. SR 3.2.2.1 must be satisfied prior to increasing power above the extrapolated allowable power level or restoration of any reduced Reactor Trip System setpoints. When $F_{\Delta H}^{N}$ is measured at reduced power levels, the allowable power level is determined by evaluating $F_{\Delta H}^{N}$ for higher power levels.

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

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

SR 3.2.2.1 is modified by a Note. The Note applies during power ascensions following a plant shutdown (leaving MODE 1). The Note allows for power ascensions if the surveillances are not current. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. Equilibrium conditions are achieved when the core is sufficiently stable such that uncertainties associated with the measurement are valid.

The value of $F_{\Delta H}^{N}$ is determined by either using the movable incore detector system to obtain a flux distribution map or from the power distribution information provided by an OPERABLE PDMS. A data reduction computer program then calculates the maximum value of $F_{\Delta H}^{N}$ from the measured flux distribution map. The limit of $F_{\Delta H}^{N}$ in the COLR allows for 4% measurement uncertainties, applicable for either flux distribution maps or PDMS-derived $F_{\Delta H}^{N}$ values (References 4 & 5).

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.2.2.1 (continued) 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. Performing this Surveillance in MODE 1 prior to exceeding 75% RTP, or at a reduced power level at any other time, and meeting the 100% RTP $F^N_{\Delta H}$ limit, provides assurance that the $F^N_{\Delta H}$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased. 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 1.77, Rev. 0, May 1974. 2. 10 CFR 50, Appendix A, GDC 26, 1971. 3. 10 CFR 50.46. 4. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994. 5. WCAP-12472-P-A, Addendum 4, Revision 0, "BEACON Core Monitoring and Operations Support System," September 2012

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 Axial Flux Difference (AFD)

BASES

BACKGROUND

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

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

The AFD is monitored on an automatic basis using the plant 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 if the AFD for two or more OPERABLE excore channels is outside its specified limits.

Although the RAOC defines limits that must be met to satisfy safety analyses, typically an operating scheme, is used to control axial power distribution in day to day operation (Ref. 1). This requires that the AFD be controlled within a band around a burnup dependent target to minimize the variation of axial peaking factors and axial xenon distribution during unit maneuvers.

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The AFD is a measure of the axial power distribution skewing to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution, and, to a lesser extent, reactor coolant temperature and boron concentration. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements. The RAOC methodology (Ref. 2) establishes a xenon distribution library with tentatively wide AFD limits. One dimensional axial power distribution calculations are then performed to demonstrate that normal operation power shapes are acceptable for the LOCA and loss of flow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements. The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also restrict the range of power distributions that are used as initial conditions in the analyses of Condition II, III, or IV events. Compliance with these limits ensures that the fuel cladding integrity is maintained for these postulated accidents. The most important Condition IV event is the LOCA. The most important Condition III event is the complete loss of forced RCS flow accident. The most important Condition II events are uncontrolled bank withdrawal and boration or dilution accidents. Condition II accidents 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 turbine load changes. Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 3). Separate signals are taken from the top and bottom power range detectors. The AFD is defined as the difference in normalized flux signals between the top

(continued)

BASES

LCO (continued)	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. The AFD limits are provided in the COLR. The AFD limits for RAOC do not depend on the target flux difference. However, the target AFD may be used to minimize changes in the axial power distribution. Violating this LCO on the AFD could produce unacceptable consequences if a Condition II, III, or IV event occurs while the AFD is outside its specified limits.
APPLICABILITY	The AFD requirements are applicable in MODE 1 greater than or equal to 50% RTP when the combination of THERMAL POWER and core peaking factors are of primary importance in safety analysis. For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.
ACTIONS	A.1 As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.2.3.1 This Surveillance verifies that the AFD, as indicated by each OPERABLE 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.
REFERENCES	1. WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974. 2. WCAP-10216-P-A, Revision 1A, Relaxation of Constant Axial Offset Control, F_Q Surveillance Technical Specification, February 1994 (Westinghouse Proprietary). 3. UFSAR, Section 4.3.3.2.4.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 Quadrant Power Tilt Ratio (QPTR)

BASES

BACKGROUND	The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation. The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1. 6, "Control Rod Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.
APPLICABLE SAFETY ANALYSES	This LCO precludes core power distributions that violate the following fuel design criteria: a. During a large break loss of coolant accident (LOCA), there is a high level of probability that the peak cladding temperature will not exceed 2200° F (Ref. 1); b. During the Condition II partial loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition; c. During an ejected rod accident, the average fuel pellet enthalpy at the hot spot in irradiated fuel must not exceed 280 cal/gm (Ref. 2); and d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3). The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits. The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	In MODE 1, the $F_{\Delta H}^{N}$ 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, above 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 ($F_{\Delta H}^{N}$) 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 $F_{\Delta H}^{N}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% 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 a power reduction may cause a change in the tilted condition.

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

A.2

After completion of Required Action A.1, the QPTR may still exceed its limits. Any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. If the QPTR

(continued)

BASES

ACTIONS

A.2 (continued)

continues to increase, THERMAL POWER has to be reduced accordingly. 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 the intended operating conditions to support obtaining a power distribution measurement. Power distribution information can be obtained using either the movable incore detectors or from an OPERABLE Power Distribution Monitoring System (PDMS) (References 4 & 5). 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 plant and perform a flux map to verify peaking factors and that the incore quadrant power tilt and QPTR are consistent. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F^N_{\Delta H}$ 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 incore quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This

(continued)

BASES

ACTIONS

A.4 (continued)

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 remains above the 1.02 limit and a evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limit prior to increasing THERMAL POWER to above the limit of Required Action A.1. 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 excore detectors are not normalized to restore QPTR to within limit until after the evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limit, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing a power distribution measurement 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 excore detectors are normalized to restore QPTR to within limit (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 at RTP 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 achieving equilibrium conditions. Equilibrium conditions are achieved when the core is sufficiently stable at the intended operating conditions to support flux mapping. As an added precaution, if the peaking factor verification cannot be performed within 24 hours due to non-equilibrium core conditions, a maximum time of 48 hours is allowed for the completion of the verification.

This Completion Time is 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.

(continued)

BASES

ACTIONS

A.6 (continued)

Required Action A.6 is modified by a Note that states that the peaking factor surveillances must be completed when the excore detectors have been normalized to restore QPTR to within limit (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which are only required if the excore detectors were normalized to restore QPTR to within limit per Required Action A.5.

B.1

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

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

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

Input from a Power Range Neutron Flux channel is considered to be operable if the upper and lower detector currents are obtainable. The remaining portion of the channel (the electronics required to provide the channel input to the QPTR alarm) need not be operable.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.2.4.2 (continued)

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

For purposes of monitoring the QPTR when one power range channel is inoperable, power distribution information can be obtained using either the movable incore detectors or from an OPERABLE Power Distribution Monitoring System (PDMS) (References 4 and 6).

The moveable incore detectors can be used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. The incore detector monitoring is performed with a full incore flux map.

The power distribution measurement is compared to the previous power distribution measurement to generate an incore QPTR. Therefore, incore QPTR can be used to confirm that excore QPTR is within limits.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore tilt result may be compared against previous tilt values either using a complete flux map or using power distribution information obtained from an OPERABLE Power Distribution Monitoring System (PDMS) (References 4 and 6). Nominally, quadrant tilt from the Surveillance should be within 2% of the tilt shown by the most recent power distribution measurement data.

BASES

REFERENCES

1. 10 CFR 50.46.
2. Regulatory Guide 1.77, Rev 0, May 1974.
3. 10 CFR 50, Appendix A, GDC 26, 1971.
4. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.
5. WCAP-12472-P-A, Addendum 4, Revision 0, "BEACON Core Monitoring and Operations Support System," September 2012
6. NRC SER for License Amendments 164 and 166, "Issuance of Amendment - Use of a Power Distribution Monitoring System", transmitted via letter to PG&E dated March 31, 2004.

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.

The LSSS, as defined in 10 CFR 50.36, are defined in this specification as the Allowable Values, and in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

During AOOs, which are those events expected to occur more than once 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 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50.67 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 occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

(continued)

BASES

BACKGROUND (continued)

The RTS instrumentation is segmented into four distinct but interconnected modules 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 Digital 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 fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

<u>Field Transmitters or Sensors</u>

To meet the design demands for redundancy and reliability, more than one, and 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 Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

<u>Signal Process Control and Protection System</u>

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

(continued)

BASES

BACKGROUND

Signal Process Control and Protection System (continued)

in the UFSAR (References 1, 2, 3, 9, 10, & 11). 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, except in the case of the seismic, turbine stop valve position, auto stop oil pressure, 12-kV bus and RCP breaker inputs which do not go through signal conditioning. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

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

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. In the case of the Digital Feedwater Control System (DFWCS), the median/signal select (MSS) feature prevents control/protection interaction even though there are only three inputs and 2-out-of-3 logic. For more detailed description, refer to B3.3.1 Applicable Safety Analyses, LCO, and Applicability, Function 14. 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 reactor is at power may be accomplished without causing a trip. The process Protection System is designed to permit any one channel to be tested and maintained at power in a bypass mode. If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room as required by applicable codes and standards. As an alternative to testing in the bypass mode, testing in the trip mode is also possible and permitted.

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BASES

BACKGROUND (continued)

Trip Setpoints and Allowable Values

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the two sided tolerance band for CHANNEL CALIBRATION tolerance. The calibration tolerance, after conversion, should correspond to the rack comparator setting accuracy defined in the latest setpoint study.

The Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 1. 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 Trip Setpoints and Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems Diablo Canyon Units 1 & 2, 24 Month Fuel Cycle and Replacement Steam Generator Evaluation," September 2007 (Ref. 17) and calculation NSP-1-20-13F (Ref. 18) and NSP-2-20-13F (Ref. 19). Interlock setpoints are Nominal Values provided in the PLS (Westinghouse Precautions Limitations and Setpoints) and their allowable values are calculated in Calculation J-110 Rev 5 (Ref. 20). The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for Rack Drift and Rack Measuring and Test Equipment uncertainties. 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.

Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Since there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift in excess of the allowance that is more than occasional may be indicative of more serious problems and warrants further investigation. In the event a channel's setpoint is found nonconservative with respect to the specified Trip Setpoint, but more conservative than the Allowable Value, the setpoint must be adjusted consistent with the Trip Setpoint value. When a channel's Trip Setpoint is nonconservative with respect to the Allowable Value, declare the channel inoperable and apply the applicable ACTION statement until the channel is returned to OPERABLE status with its Setpoint adjusted consistent with the Trip Setpoint value.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Setpoints in accordance with the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Allowable Values of Table 3.3.1-1 are the LSSS as defined in 10 CFR 50.36.

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. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal, or in the case of the Power Range channels the test signal is added to 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.

The Trip Setpoints and Allowable Values listed in Table 3.3.1-1 are based on the methodology described in Reference 17, 18, 19, and 20, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value. This also applies to the Overtemperature ΔT and Overpower ΔT K values per reference 16. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Trip Setpoints may be administratively redefined in the conservative direction for several reasons including startup, testing, process error accountability, or even a conservative response for equipment malfunction or inoperability. Some trip functions have historically been redefined at the beginning of each cycle for purposes of startup testing, e.g. Power Range Newtron Flux High and Overtemperature ΔT. Calibration to within the defined calibration tolerance of an administratively redefined, conservative Tip Setpoint is acceptable. Redefinition at full power conditions for these functions is expected and acceptable.

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 reactor trip and/or ESF actuation for the unit. If both trains are taken out of service

(continued)

BASES

BACKGROUND

Solid State Protection System (continued)

or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

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

The bistable outputs from the signal processing equipment or relay contact input (RCP breaker, 12-kV UV/UF, seismic, etc.) are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various unit 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.

Reactor Trip Switchgear

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 reactor trip breaker is also equipped with an automatic shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the SSPS. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

(continued)

BASES

BACKGROUND	Reactor Trip Switchgear (continued) The decision logic matrix Functions are described in the functional diagrams included in Reference 1. 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 decision logic matrix Functions while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The RTS functions to maintain the applicable limits 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. 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. Generally 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. In the case of the Digital Feedwater Control System, the Median Signal Select feature prevents control/protection interaction even though there are only three inputs and a 2-out-of-3 logic. For more detailed description, refer to B3.3.1 Applicable Safety Analyses, LCO, and Applicability, Function 14. 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 channels. Three OPERABLE instrumentation channels in a

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one, channel to be tripped during maintenance or testing without causing a reactor trip. 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 (1-out-of-2 coincidence). 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 and all of the rods are fully 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.

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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. 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 fuel damage. Reactivity excursions can be caused by rod withdrawal or inadvertent CVCS malfunction, or for example, by sudden changes in RCS coolant temperature such as a feedwater system malfunction (Ref. 12).

The LCO requires all four of the Power Range Neutron Flux—High channels to be OPERABLE (2-out-of-4 coincidence).

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.

b. Power Range Neutron Flux—Low

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

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Power Range Neutron Flux—Low (continued)

The LCO requires all four of the Power Range Neutron Flux—Low channels to be OPERABLE (2-out-of-4 coincidence).

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 or equal to 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.

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 complements the Power Range Neutron 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 (2-out-of-4 coincidence).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	<u>Power Range Neutron Flux—High Positive Rate</u> (continued) 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 withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires two channels of Intermediate Range Neutron Flux to be OPERABLE (1-out-of-2 coincidence). Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

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 Intermediate Range Neutron Flux trip is not required because the Source Range Neutron Flux trip function provides core protection for reactivity accidents. Although this mode applicability is different from the Technical Specifications prior to License Amendment 135, where the Applicability was Mode 1 below P-10 and Mode 2, no changes to plant operations or procedures are expected. Since the Intermediate Range channels must be OPERABLE prior to entering the new Applicability per LCO 3.0.4, and the time frame for non-applicability is small and more difficult to control administratively than by the current Mode 2 limitation, DCPP will conservatively consider the Applicability as Mode 1 below P-10 and Mode 2. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Intermediate Range Neutron Flux (continued)

The reactor cannot be started up in this condition. 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 2 below P-6, 3, 4, and 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. Therefore, the functional capability at the Trip Setpoint is assumed to be available.

The LCO requires two channels of Source Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. The LCO also requires one channel of the Source Range Neutron Flux to be OPERABLE in MODE 3, 4, or 5 with RTBs open or the control rods incapable of withdrawal. In this case, the source range Function is to provide control room indication. The outputs of the Function to RTS logic are not required OPERABLE in MODE 6 or when the RTBs are open or all rods are fully inserted and the Rod Control System is incapable of withdrawal.

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events. The Function also provides neutron flux indication in the control room.

In MODE 2 when below the P-6 setpoint during a reactor startup, the Source Range Neutron Flux trip must be OPERABLE (1-out-of-2 coincidence). 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.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	5. <u>Source Range Neutron Flux</u> (continued) Above the P-6 setpoint, the NIS source range neutron flux trip may be manually blocked and the high voltage to the detectors may be de-energized. Below the P-6 setpoint, the source range neutron flux trip is automatically reinstated and the high voltage to the detectors is automatically energized. In MODES 3, 4, and 5 with the reactor shut down, but with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted, the Source Range Neutron Flux trip Function must also be OPERABLE (1-out-of-2 coincidence) to provide core protection against a rod withdrawal accident. If the Rod Control System is not capable of rod withdrawal, the source range detectors are not required to trip the reactor. However, their monitoring Function must be OPERABLE to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like an uncontrolled boron dilution. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.3, "Nuclear Instrumentation."

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 and it protects against vessel exit bulk boiling and ensures that the exit quality is within the limits defined by the DNBR correlation. The inputs to the Overtemperature ΔT trip include pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature—the 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

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.

ΔT_0, as used in the overtemperature and overpower ΔT trips, represents the 100 percent RTP value of ΔT as measured for each loop. For the initial startup of a refueled core, ΔT_0 is initially assumed to be the same as the measured ΔT value from the previous cycle until ΔT is once again measured at full power. Accurate determination of the loop specific ΔT values are made quarterly when performing the incore/excore recalibration at steady-state conditions (i.e., power distribution conditions not affected by xenon or other transient conditions). The indicated ΔT variation between loops is due to the difference between hot leg temperatures and hot leg temperature measurement biases. The hot leg temperature variance between loops is primarily caused by asymmetrical flow in the upper plenum, and the difference in hot leg temperature measurement biases primarily caused by differences in hot leg temperature streaming error between loops. The loop ΔTs change with burn up which result from the change in the hot leg streaming biases as the radial power distribution changes.

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; thus the actuation logic must be able to withstand an input failure to the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

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. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE . Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions.

Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions. In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB (2-out-of-4 coincidence). 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 for Condition I and II events (Ref. 12). 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. The Overpower ΔT trip also provides protection to mitigate the consequences of small steamline breaks, as reported in WCAP-9226, Ref. 16, and steamline breaks with coincident control rod withdrawal (Ref. 3). 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Overpower ΔT (continued)

ΔT_0 , as used in the overtemperature and overpower ΔT trips, represents the 100 percent RTP value of ΔT as measured for each loop. For the initial startup of a refueled core, ΔT_0 is initially assumed to be the same as the measured ΔT value from the previous cycle until ΔT is once again measured at full power. Accurate determination of the loop specific ΔT values are made quarterly when performing the incore/excore recalibration at steady-state conditions (i.e., power distribution conditions not affected by xenon or other transient conditions). The indicated ΔT variation between loops is due to the difference between hot leg temperatures and hot leg temperature measurement biases. The hot leg temperature variance between loops is primarily caused by asymmetrical flow in the upper plenum, and the difference in hot leg temperature measurement biases is primarily caused by differences in hot leg temperature streaming error between loops. The loop ΔTs change with burn up which result from the change in the hot leg streaming biases as the radial power distribution changes.

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. The temperature signals are used for other control functions; thus, 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 remaining 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. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE (2-out-of-4 coincidence). Note that the Overpower ΔT trip Function receives input 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure—High and —Low trips and the Overtemperature ΔT trip. The Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System; thus, 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.

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 four channels of Pressurizer Pressure—Low to be OPERABLE (2-out-of-4 coincidence).

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 Low Pressure Permissive 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, there is insufficient heat production to be concerned about DNB.

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 four channels of the Pressurizer Pressure—High to be OPERABLE (2-out-of-4 coincidence).

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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Pressurizer Pressure—High (continued)

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 usually be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Two low temperature overpressure protection system channels provide overpressure protection with the PORVs when below the low temperature cut-off specified in the pressure and temperature limits report (PTLR).

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 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 (2-out-of-3 coincidence). 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

Each 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 (2-out-of-3 coincidence in one loop).

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow—Low trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since there is insufficient heat production to be concerned about DNB. 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, 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.

The allowable value and nominal trip setpoint are based on a percentage of the loop flow measured every 24 months by SR 3.4.1.4. The RCS cold leg elbow taps indicated flow is continuously compared to the Reactor Coolant Flow-Low nominal trip setpoint.

11. Reactor Coolant Pump (RCP) Breaker Position

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

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE (2-out-of-4 coincidence). 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, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

In MODE 1 above the P-7 setpoint , the RCP Breaker Position trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since there is insufficient heat production to be concerned about DNB. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled.

12. Undervoltage Reactor Coolant Pumps

The Undervoltage RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in all RCS loops. The voltage to each bus is monitored by one relay on each RCP for two relays per bus (1/2 coincidence on 2/2 buses). Above the P-7 setpoint, a loss of voltage detected on both RCP buses, i.e. a complete loss of flow event, will initiate a reactor trip. For this event, the under voltage trip Function will generate a reactor trip before the Reactor Coolant Flow—Low Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires two Undervoltage RCPs channels per bus to be OPERABLE (2 pumps per Bus with one channel per pump).

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 there is insufficient heat production to be concerned about DNB. Above the P-7 setpoint, the reactor trip on loss of flow in all four 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. An adequate 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 by two relays on one RCP bus will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow—Low Trip Setpoint is reached.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

13. Underfrequency Reactor Coolant Pumps (continued)

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 per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Underfrequency RCPs trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since there is insufficient heat production to be concerned about DNB. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

14. Steam Generator Water Level—Low Low

a. The SG Water Level—Low Low trip Function ensures that protection is provided against a loss of heat sink in the event of a loss of feedwater flow to one or more SGs. 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. 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 and four channels of RCS ΔT(1/loop) to be OPERABLE. The installation of the median signal selector (MSS) and four channels of RCS ΔT (1/loop) effectively eliminates the possibility that a single random failure could cause a control system action that results in a condition requiring protection action, and also prevent proper operation of a protection system channel designed to protect against the condition. Together with the MSS, the Steam Flow Arbitrator (SFA) eliminates the possibility that failure of the instrument tap shared between one narrow-range level channel and one steam flow channel on each steam generator will cause a transient that would require protective action by any of the level channels. The MSS prevents the resulting failed high narrow range level signal from causing a level transient via the level portion of the DFWCS. The SFA prevents the resulting failed low steam flow signal from causing a level transient via the feed forward mass balance portion of the DFWCS.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Thus, the MSS prevents interaction between the feedwater control and reactor protection systems in accordance with the requirements of IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations." Removal of this interaction eliminates the need for the low feedwater flow reactor trip. The MSS will functionally separate steam generator narrow range level protection channels (low-low steam generator water level trip) to provide compliance with IEEE 279-1971 and satisfy the original design basis. Additionally, since no adverse control system action can result from a single failed protection system instrument channel (including the shared instrument tap), a second random protection system failure, as would otherwise be required by IEEE 279-1971, need not be considered. This trip is actuated on two out of three low-low water level signals occurring in any steam generator. If a low-low water level condition is detected in one steam generator, signals shall be generated to trip the reactor and start the motor driven auxiliary feedwater pumps. If a low-low water level condition is detected in two or more steam generators, a signal is generated to start the turbine driven auxiliary feedwater pump as well.

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 (primarily PG&E Design Class II). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level—Low Low Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 (and 4, prior to going on RHR) and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

    b. The signals to actuate reactor trip and start auxiliary feedwater pumps may be delayed through the use of a Trip Time Delay (TTD) system for reactor power levels below 50% of RTP. Low-low water level in any protection set in any steam generator will generate a signal which starts an elapsed time trip delay timer.

    Table 3.3.1-1 uses the term channel when designating the required number instrument channels to meet the LCO for a function. In the case of the TTD system, each channel is not actually an instrument channel, but imbedded software which acts as a processor.

    Two of the four TTD processors provide an output to each of the four-steam generators low-low level trip functions. The other two TTD processors each provide inputs to the low-low level steam generators trip functions for two of the four steam generators.

    The steam generator water level-low low trip requires two trip signals from any one steam generator. Together the four TTD processors provide the low power time delay for the three outputs to each of the four steam generator low-low level trip functions.

    The allowable trip time delay is based upon the prevailing power level at the time the low-low level trip setpoint is reached. The Time Delay value used is determined as directed under Note 3. If power level rises after the trip time delay setpoints have been determined, the trip time delay is re-determined (i.e., decreased) according to the increase in power level. However, the trip time delay is not changed if the power level decreases after the delay has been determined. The use of this delay allows added time for natural steam generator level stabilization or operator intervention to avoid an inadvertent protection system actuation.

15. Steam Generator Water Level—Low, Coincident With Steam Flow/Feedwater Flow Mismatch - Not used.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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-9 setpoint, less than or equal to 50% power, will not actuate a reactor trip. Three pressure switches monitor the trip oil pressure in the Turbine 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 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 Autostop Oil Pressure to be OPERABLE in MODE 1 above P-9 (2-out-of-3 coincidence).

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip—Low 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. 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. Any turbine trip from a power level below the P-9 setpoint, less than or equal to a maximum setpoint of 50 percent power, will not actuate a reactor trip.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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 above P-9.

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-9. All four channels must trip to cause reactor trip.

Below the P-9 setpoint, a load rejection can be accommodated by the Steam Dump and Reactor Control Systems. 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 small break LOCA but rod insertion is not credited for the large break LOCA (Ref. 3).

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.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by logic in the SSPS circuitry of ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

17. Safety Injection Input from Engineered Safety Feature Actuation System (continued)

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2 (1-out-of-2 coincidence).

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. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

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 and allows the high voltage to be de-energized. 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, and
- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint (1-out-of-2 coincidence).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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.

Trip Setpoint and Allowable Value are not applicable to the P-7 interlock because it is a logic Function and thus has no parameter with which to associate an LSSS. The P-7 train is operable if the P-10 and P-13 interlocks are in their required states based on plant conditions.

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 (1-out-of-2 coincidence).

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 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 35% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow—Low reactor trips on low flow in one or more RCS loops on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 35% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Power Range Neutron Flux, P-8 (continued)

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1 (2-out-of-4 coincidence).

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

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock is actuated at less than or equal to 50% power as determined by two-out-of-four NIS power range detectors. 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-9 setpoint. Above the P-9 setpoint, a turbine trip may challenge the pressurizer PORVs due to the mismatch between reactor power and the capacities of the Steam Dump and Reactor Control Systems. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor. Up to one group of 40% steam dump valves (or equivalent relief capacity) may be removed from service without having an adverse impact on their design function with respect to the design basis for the P-9 setpoint.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1 (2-out-of-4 coincidence).

In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a significant load rejection beyond the capacity of the Steam Dump System.

e. Power Range Neutron Flux, P-10

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

- 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 back up signal to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detectors high voltage and allows manual block of the IR rod stop;
- the P-10 interlock provides one of the two inputs to the P-7 interlock;
- 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); and
- on decreasing power, the P-10 interlock automatically defeats the block of the source range neutron flux trip and with P-6 energizes the source range high voltage.

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2 (2-out-of-4).

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

f. Turbine Impulse Chamber Pressure, P-13

The Turbine Impulse Chamber Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than 10% of Turbine Power. The interlock 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 Chamber Pressure, P-13 interlock to be OPERABLE in MODE 1 (1-out-of-2-coincidence).

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

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, the trip logic, and 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 (1-out-of-2 coincidence). 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical (1-out-of-2 coincidence). 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 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 (1-out-of-2 coincidence). 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.

22. Seismic Trip

The seismic trip system operates to shut down reactor operations should ground accelerations exceed a preset level in any of the three orthogonal directions monitored (one vertical, two horizontal).

Three triaxial sensors (accelerometers) are anchored to the containment base in three separate locations 120 degrees apart. Each senses acceleration in three mutually orthogonal directions. Output signals are generated when ground accelerations exceed the preset level. These signals are transmitted to the Trains A and B Solid State Protection System (SSPS). If two of the three sensors in any direction produce simultaneous outputs, the logic produces trains A and B reactor trip signals.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	22. Seismic Trip (continued) This trip function must be OPERABLE in MODE 1 or 2 when the reactor is critical and must be capable to shut down the reactor in the event of an earthquake. Three channels in these directions are required to be OPERABLE. 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. 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 3.3.1-1 are specified (e.g., on a per steam line, per loop, per SG), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate. In the event a channel's setpoint is found nonconservative with respect to the specified Trip Setpoint, but more conservative than the Allowable Value, the setpoint must be adjusted consistent with the Trip Setpoint value. When a channel's Trip Setpoint is nonconservative with respect to the Allowable Value, declare the channel inoperable and apply the applicable ACTION statement until the channel is returned to OPERABLE status with its Setpoint adjusted consistent with the Trip Setpoint value. When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation. A.1 Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

(continued)

BASES

ACTIONS (continued)

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 exit the applicability from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, Condition C is entered if the Manual Reactor Trip Function has not been restored and the Rod Control System is capable of rod withdrawal or one more rods are not fully inserted.

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

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

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the SSPS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status action must be initiated within the same 48 hours to fully insert all rods, and the Rod Control System must be rendered

(continued)

BASES

ACTIONS

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

incapable of rod withdrawal within the next hour (e.g., by de-energizing all CRDMs, by opening the RTBs, or by de-energizing the motor generator (MG) sets). The additional hour for the latter provides sufficient time to accomplish the action in an orderly manner. With the rods fully inserted and the Rod Control System rendered 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.

Condition C is modified by a Note stating that while this LCO is not met for Functions 19, 20, or 21 in MODE 5 making the Rod Control System capable of rod withdrawal is not permitted. This note is in addition to the requirements of LCO 3.0.4 which preclude the transition from either MODE 3 or MODE 4 to MODE 3 or MODE 4 with the Rod control System capable of rod withdrawal or all rods not fully inserted for Functions 19, 20, or 21 with one channel or train inoperable.

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

Condition D applies to the Power Range Neutron Flux—High Function.

With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost. Therefore, SR 3.2.4.2 must be performed (Required Action D.1.1) within 12 hours after THERMAL POWER exceeds 75% RTP and every 12 hours thereafter. If reactor power decreases to $\leq$ 75% RTP, the measurement of both intervals stops, and SR 3.2.4.2 is no longer required. New intervals start upon reactor power exceeding 75% RTP. 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. When THERMAL POWER is $\leq$ 75%, core radial power distributions are prevented from exceeding design limits where DNB conditions may exist. The 12-hour Completion Time is consistent with the Surveillance Requirement Frequency in LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The NIS power range detectors provide input to the Rod 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 28.

(continued)

BASES

ACTIONS

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

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight hours are allowed to place the plant in MODE 3. The 78-hour completion time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction as required by Action D.2. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. In accordance with WCAP 10271-P-A (Reference 7), very specific circumstances are related to the use of this bypass condition. Since the NIS channels are not designed with Bypass-capable logic that meets the requirements of IEEE 279, the provisions for bypass only apply to a specific type of channel failure. To apply, the channel must fail in such a way that it does not trip the bistables. With this type of failure, the channel may be returned to service and considered "bypassed" under this Note. Specifically, the bypass condition is the state when a failed channel is taken out of the forced "tripped" state and placed in operation. Due to the failed nature of the channel, the channel cannot be assumed to be OPERABLE, and is therefore considered to be in a state of bypass when the channel failure is such that its bistables are not tripped. The provisions of WCAP 10271 specifically prohibit the use of jumpers or lifted leads to bypass these channels. In this configuration, a second channel can be tested or setpoints adjusted with the channel in the tripped mode without completing reactor trip logic. The 12 hour time limit is justified in Reference 28.

Required Action D.1.1 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. The performance of SR 3.2.4.2 per ACTION D.1.1 is subject to the SR 3.2.4.2 note. 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 core power distribution measurement information once per 12 hours may not be necessary.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux—Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Power Range Neutron Flux—High Positive Rate;
- Pressurizer Pressure—High; and
- SG Water Level—Low Low.

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 28.

If the operable 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 for Functions 6, 7 and 8.b, that allows an inoperable channel and/or one additional channel to be tested with one channel in bypass and the other channel in trip for up to 12 hours for performing surveillance testing. Additionally, for Function 6, 7 and 8b, both the inoperable and the additional channel maybe placed in bypass for up to 12 hours for surveillance testing. The Note allows only the inoperable channel for Functions 2.b and 3, to be bypassed for up to 12 hours for surveillance testing of other channels. This note is not intended to allow simultaneous testing of coincident channels on a routine basis. In accordance with WCAP 10271, very specific circumstances are related to the use of this bypass condition for RTS Functions 2.b and 3. Since these channels are not designed with Bypass-capable logic that meets the requirements of IEEE 279, the provisions for bypass only apply to a specific type of channel failure. To apply, the channel must fail in such a way that it does not trip the bistables. With this type of failure, the channel may be returned to service and considered "bypassed" under this Note. Specifically, the bypass condition is the state when a failed channel is taken out of the forced "tripped" state and placed in operation.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

Due to the failed nature of the channel, the channel cannot be assumed to be OPERABLE, and is therefore considered to be in a state of bypass when the channel failure is such that its bistables are not tripped. The provisions of WCAP 10271 specifically prohibit the use of jumpers or lifted leads to bypass these channels. In this configuration, a second channel can be tested with the channel in the tripped mode without completing reactor trip logic. The Note for Function 14.a, allows the inoperable channel and/or one additional channel to be tested with one channel in bypass and the other in trip for up to 12 hours for surveillance testing. Functions 6,7, and 8.b are two-out-of-four trip logic, and 14.a is two-out-of-three trip logic and the allowed testing configurations provide flexibility for testing, while assuring that during testing no configuration will cause an inadvertent trip of the reactor or keep a valid signal from tripping the reactor as it was designed. This note is not intended to allow simultaneous testing of coincident channels on a routine basis. The 12 hour time limit is justified in Reference 28.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, the overlap of the power range detectors, 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.

(continued)

BASES

ACTIONS (continued)

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 the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

Required Action G.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided the SDM limits specified in the COLR are met and the requirements of LCOs 3.1.5, 3.1.6, and 3.4.2 are met.

H.1 - Not used

(continued)

BASES

ACTIONS (continued)

I.1

Condition I 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 I.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided the SDM limits specified in the COLR are met and the requirements of LCOs 3.1.5, 3.1.6, and 3.4.2 are met.

J.1

Condition J applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and performing a reactor startup, or in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition and the unit enters Condition L.

(continued)

BASES

ACTIONS (continued)

K.1, K.2.1, and K.2.2

Condition K 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 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 fully insert all rods. 1 additional hour is allowed to place the Rod Control System in a condition incapable of rod withdrawal (e.g., by de-energizing all CRDMs, by opening the RTBs, or by de-energizing the motor generator (MG) sets). Once these ACTIONS are completed the core is in a more stable condition. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to place the Rod Control System in a condition incapable of rod withdrawal, are justified in Reference 7.

L.1 and L.2

Condition L applies when the required number of OPERABLE Source Range Neutron Flux channels is not met in MODE 3, 4, or 5 with the RTBs open or with the Rod Control System incapable of rod withdrawal and all rods fully inserted. With the unit in this Condition, the NIS source range performs a monitoring function. With less than the required number of source range channels OPERABLE, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation.

Also, 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, core protection 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 L.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.

Required Action L.1 is modified by a Note which permits plant temperature changes provided the temperature change is accounted for in the calculated SDM. Introduction of temperature changes, including temperature increases when operating with a positive MTC, must be evaluated to ensure they do not result in a loss of required SDM.

(continued)

BASES

ACTIONS (continued)

M.1 and M.2

Condition M applies to the following reactor trip Functions:

- Pressurizer Pressure — Low;
- Pressurizer Water Level — High;
- Reactor Coolant Flow — Low;
- RCP Breaker Position ;
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. For the Pressurizer Pressure - Low, Pressurizer Water Level - High, Undervoltage RCPs, 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 trip Function, placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 and P-8 setpoints. 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. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 28. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time. The Reactor Coolant Flow - Low reactor trip function goes from 1 of 4 logic to 2 of 4 logic below the P-8 setpoint; however, the Required Action must take the plant below the P-7 setpoint, if an inoperable channel is not tripped within 72 hours, due to the shared components between this function and the Reactor Coolant Flow - Low trip function.

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 M.

(continued)

BASES

ACTIONS

M.1 and M.2 (continued)

The Required Actions have been modified by a Note for Function 8.a, that allows the inoperable channel and/or one additional channel to be tested with one channel in bypass and the other in trip, or with both the inoperable channel and the additional channel in bypass for up to 12 hours while performing surveillance testing of those channels. The Note for Function 9 and 10 allows the inoperable channel and/or one additional channel to be tested with one channel in bypass and the other channel in trip for up to 12 hours for surveillance testing. The Note allows only the inoperable channel for Functions 12 and 13 to be bypassed for surveillance testing of other channels. This note is not intended to allow simultaneous testing of coincident channels on a routine basis. In accordance with WCAP 10271, very specific circumstances are related to the use of this bypass condition for RTS Functions 12 and 13. Since these channels are not designed with Bypass-capable logic that meets the requirements of IEEE 279, the provisions for bypass only apply to a specific type of channel failure. To apply, the channel must fail in such a way that it does not trip the bistables. With this type of failure, the channel may be returned to service and considered "bypassed" under this Note. Specifically, the bypass condition is the state when a failed channel is taken out of the forced "tripped" state and placed in operation. Due to the failed nature of the channel, the channel cannot be assumed to be OPERABLE, and is therefore considered to be in a state of bypass when the channel failure is such that its bistables are not tripped. The provisions of WCAP 10271 specifically prohibit the use of jumpers or lifted leads to bypass these channels. In this configuration, a second channel can be tested with the channel in the tripped mode without completing reactor trip logic. Function 11 may not be bypassed since its logic is not 2 of 4 or 2 of 3, therefore, single failure would not be maintained. Function 8.a is a two-out-of-four trip logic and Functions 9 and 10 are two-out-of-three logic trip logics. The allowed testing configurations provide flexibility for testing, while assuring that during testing no configuration will cause an inadvertent trip of the reactor or keep a valid signal from tripping the reactor as it was designed. This note is not intended to allow simultaneous testing of coincident channels on a routine basis. The 12 hour time limit is justified in Reference 28.

(continued)

BASES

ACTIONS (continued)

N.1 and N.2

Condition N applies to the RCP Breaker Position reactor trip function.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. The 6 hours allowed to place the channel in the tripped condition is justified in Reference 7. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition N.

Function 11 may not be bypassed since its logic is not 2 of 4 or 2 of 3, therefore, single failure would not be maintained.

(continued)

BASES

ACTIONS (continued)

O.1 and O.2

Condition O applies to Turbine Trip on Low Auto-Stop Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 12 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-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 28.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. In accordance with WCAP 10271, very specific circumstances are related to the use of this bypass condition for RTS Function 16. Since this channel is not designed with Bypass-capable logic that meets the requirements of IEEE 279, the provisions for bypass only apply to a specific type of channel failure. To apply, the channel must fail in such a way that it does not trip the bistables. With this type of failure, the channel may be returned to service and considered "bypassed" under this Note. Specifically, the bypass condition is the state when a failed channel is taken out of the forced "tripped" state and placed in operation. Due to the failed nature of the channel, the channel cannot be assumed to be OPERABLE, and is therefore considered to be in a state of bypass when the channel failure is such that its bistables are not tripped. The provisions of WCAP 10271 specifically prohibit the use of jumpers or lifted leads to bypass this channel. In this configuration, a second channel can be tested with the channel in the tripped mode without completing reactor trip logic. The 12 hour time limit is justified in Reference 28.

P.1 and P.2

Condition P applies to Turbine Trip on Turbine Stop Valve Closure. With one or more channels inoperable, the inoperable channel must be placed in the trip condition within 72 hours. For the Turbine Trip on Turbine Stop Valve Closure function, where four-of-four channels are required to initiate a reactor trip; hence more than one channel may be placed in trip. If the channel(s) cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel(s) in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 28.

(continued)

BASES

ACTIONS (continued)

Q.1 and Q.2

Condition Q 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 Q.1) or the unit must be placed in MODE 3 within the next 6 hours. The 24 hours allowed to restore the inoperable train to OPERABLE status is justified in Reference 29. An additional 6 hours is allowed to place the unit in MODE 3. Six hours (Required Action Q.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

Consistent with the requirement in Reference 28 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included. These restrictions do not apply when a logic train is being tested under the 4-hour bypass Note of Condition Q. When a logic train is inoperable for maintenance, the following should not be scheduled:

- Activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip (to preserve ATWS mitigation capability).
- Activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable (to preserve reactor trip and safeguards actuation capability).
- Activities that prevent maintaining one complete emergency core cooling system train that can be actuated automatically (to preserve LOCA mitigation capability).
- Activities on electrical systems (e.g., AC and DC power) and cooling systems (ASW and CCW) that support the systems or functions listed above.

Since Condition Q is typically entered due to equipment failure, it follows that some of the above restrictions may not be met at the time of Condition Q entry. If this situation were to occur during the 24-hour Completion Time of Required Action Q.1, the configuration risk management program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition Q or fully implement the restrictions.

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.

(continued)

BASES

ACTIONS (continued)

R.1 and R.2

Condition R applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours is allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24-hour Completion Time is justified in Reference 29. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in Condition C entry if one RTB train is inoperable.

Consistent with the requirement in Reference 29 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a RTB train is inoperable for maintenance are included. These restrictions do not apply when a RTB train is being tested under the 4-hour bypass Note of Condition R. When a RTB train is inoperable for maintenance, the following should not be scheduled:

- Activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip (to preserve ATWS mitigation capability).
- Activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable (to preserve reactor trip and safeguards actuation capability).
- Activities on electrical systems (e.g., AC and DC power) and cooling systems (ASW) that support the systems or functions listed above.

Since Condition R is typically entered due to equipment failure, it follows that some of the above restrictions may not be met at the time of Condition R entry. If this situation were to occur during the 24-hour Completion Time of Required Action R.1, the configuration risk management program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition R or fully implement the above restrictions.

The Required Actions have been modified by a Note. The Note allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The 4-hour time limit is justified in Reference 29.

(continued)

BASES

ACTIONS (continued)

S.1 and S.2

Condition S applies to the P-6 and P-10 interlocks. With one or more channels inoperable, the associated interlock must be verified by observation of the associated permissive annunciator window 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.

T.1 and T.2

Condition T applies to the P-7, P-8, P-9, and P-13 interlocks. With one or more channel(s) inoperable, the associated interlock must be verified by observation of the associated permissive annunciator window 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.

(continued)

BASES

ACTIONS (continued)

U.1 and U.2

Condition U 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, Condition C is entered if the inoperable trip mechanism has not been restored and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to restore the inoperable trip mechanism to OPERABLE status, consistent with Ref. 13.

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

V.1 - Not used

W.1 and W.2

Condition W applies to the Seismic Trip, in MODES 1 and 2. With one of the channels inoperable, START UP and/or POWER OPERATION may proceed provided the inoperable channel is placed in trip within the next 6 hours. If a direction is inoperable, then the channel must be considered inoperable. Placing the channel in the tripped condition creates a partial trip condition requiring only one out of two logic from the remaining locations for reactor trip actuation.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 72 hours while performing surveillance testing or maintenance. The allowed 72 hour bypass time is reasonable based on the low probability of an event occurring while the channel is bypassed and on the time required to perform the required surveillance testing.

(continued)

BASES

ACTIONS (continued)

X.1, X.2 and X.3

Condition X applies to the Trip Time Delay (TTD) channels (processors) for the SG Water Level-Low Low trip function in MODES 1 and 2. With one or more TTD channels (processors) inoperable or the RCS delta-T equivalent power input inoperable, 72 hours are allowed to adjust the threshold power level for no time delay to 0% RTP. This sets the TTD processor timer to zero seconds and effectively removes its time delay input from the affected SG water level circuits. If the TTD processor timer cannot be set to zero seconds then the affected SG water level low-low output channels must be placed in trip. Only one SG water level low-low output channel per generator can be placed in the trip position without tripping the plant. The Completion Time of 72 hours is justified in Reference 28.

If the TTD threshold power for no time delay cannot be adjusted to 0% RTP (zero seconds time delay) or the single SG water level output 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 the inoperable TTD channel (processor) and/or one additional TTD channel (processor) to be surveillance tested with the affected SG low-low water level channels for one TTD channel (processor) in bypass and the affected SG low-low water level channels for the other TTD channel (processor) in trip for up to 12 hours. This note is not intended to allow simultaneous testing of multiple TTD channels (processors) on a routine basis.

If Required Action X.1 is completed for an inoperable TTD processor, the affected SG low-low water level channels would still be operable in that a valid SG low-low water level trip function would not be delayed. With the inoperable TTD processor meeting this required action, the above note will still apply for the inoperable TTD processor and/or one additional TTD processor.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of process protection supplies both trains of the RTS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

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.

SR 3.3.1.1

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 (continued)

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the power range channel output every 24 hours. If the calorimetric heat balance calculation results exceed the power range channel output by more than + 2% RTP, the power range channel is not declared inoperable, but the excore channel gains 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.

To assure a reactor trip consistent with the safety analysis, adjustments to the power range channel in the decreasing direction are not required. 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.

At lower power levels (<45% RTP), calorimetric data are inaccurate.

Discretion must be exercised if the power range channel output is adjusted in the decreasing power direction due to a part-power calorimetric (<45% RTP). This action could introduce a non-conservative bias at higher power levels which could delay an NIS reactor trip until power is above the power range high safety analysis limit (SAL) of 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 determined by a ΔP measurement across a feedwater venturi. While the measurement uncertainty remains constant in ΔP span 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.

To assure a reactor trip below the power range high SAL, the maximum allowable Power Range Neutron Flux-High trip Setpoint is limited according to DCPP surveillance procedures, prior to adjusting the power range channel output in the decreasing power direction whenever the calorimetric power is between 15% and 45% RTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

For example, to assure a reactor trip below the power range high SAL, the Power Range Neutron Flux-High trip Setpoint is reduced as necessary prior to adjusting the power range channel output in the decreasing power direction whenever the calorimetric power is ≥ 15% RTP and <45% RTP. The maximum allowable Power Range Neutron Flux-High trip Setpoint may be increased with increasing RTP in accordance with surveillance procedures. Following a plant refueling outage, it is prudent to reduce the Power Range Neutron Flux–High trip Setpoint prior to startup.

Before the Power Range Neutron Flux–High trip Setpoint is re-set to its nominal full power value (≤109% RTP), the power range channel calibration must be confirmed based on a calorimetric performed at ≥ 45% RTP.

The Note to SR 3.3.1.2 clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 15% RTP, but prior to exceeding 30% RTP. A power level of 15% RTP is chosen based on plant stability, i.e., automatic rod control capability and the turbine generator synchronized to the grid. The 24-hour allowance after increasing THERMAL POWER above 15% RTP provides a reasonable time to attain a scheduled power plateau, establish the requisite conditions, perform the required calorimetric measurement, and make any required adjustments in a controlled, orderly manner and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be acceptable for subsequent use.

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

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted. The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. The comparison checks for differences due to changes in core power distribution since the last calibration.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

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.

The Note to SR 3.3.1.3 clarifies that the Surveillance is required only if reactor power is ≥ 50% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 50% RTP. This Note allows power ascensions and associated testing to be conducted in a controlled and orderly manner, at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not be verified to be acceptable for subsequent use. Due to such effects as shadowing from the relatively deep control rod insertion and, to a lesser extent, the dependency of the axially-dependent radial leakage on the power level, the relationship between the incore and excore indications of axial flux difference (AFD) at lower power levels is variable. Thus, it is prudent to defer the calibration of the excore AFD against the incore AFD until more stable conditions are attained (i.e., withdrawn control rods and higher power level). The AFD is used as an input to the Overtemperature ΔT reactor trip function and for assessing compliance with ITS LCO 3.2.3, "AXIAL FLUX DIFFERENCE." Due to the DNB benefits gained by administratively restricting the power level to 50% RTP, no limits on AFD are imposed below 50% RTP by LCO 3.2.3; thus, the proposed change is consistent with LCO 3.2.3. requirements below 50% RTP. Similarly, sufficient DNB margins are realized through operation below 50% RTP that the intended function of the Overtemperature ΔT reactor trip function is maintained, even though the excore AFD indication may not exactly match the incore AFD indication. Based on plant operating experience, 24 hours is a reasonable time frame to limit operation above 50% RTP while completing the procedural steps associated with the surveillance in an orderly manner.

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 (continued)

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.

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 bypass breaker test shall include a local manual shunt trip only. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Surveillance Frequency is 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 with the RTB bypass breaker installed, 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 P-7 alarm circuit is excluded from this testing since it only mimics the actions of the SSPS and cannot prevent the permissive from performing its function. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore power distribution measurements. The incore power distribution measurements can be obtained using the movable incore detectors or an OPERABLE Power Distribution Monitoring System (PDMS) (References 26 & 33). If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is ≥ 75% RTP and that 72 hours after thermal power is ≥ 75% RTP is allowed for performing the first surveillance after reaching 75% RTP. The SR is deferred until a scheduled testing plateau above 75% RTP is attained during the post-outage power ascension. During a typical post-refueling power ascension, it is usually necessary to control the axial flux difference at lower power levels through control rod insertion. After equilibrium conditions are achieved at the specified power plateau, a power distribution measurement must be taken and the required data collected. The data is typically analyzed and the appropriate excore calibrations completed within 48 hours after achieving equilibrium conditions. An additional time allowance of 24 hours is provided during which the effects of equipment failures may be remedied and any required re-testing may be performed.

The allowance of 72 hours after equilibrium conditions are attained at the testing plateau provides sufficient time to allow power ascensions and associated testing to be conducted in a controlled and orderly manner at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be acceptable for subsequent use.

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

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

Setpoints must be 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.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 7.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

SR 3.3.1.7 is modified by two notes. Note 1 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. Note 2 requires that the quarterly COT for the source range instrumentation shall include verification by observation of the associated permissive annunciator window that the P-6 and P-10 interlocks are in their required state for the existing unit conditions. If this surveillance or if SR 3.3.1.8 has been performed within the period specified in the Surveillance Test Interval List, the requirements of this surveillance are satisfied.

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 it is modified by the same Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit conditions by observation of the associated permissive annunciator window. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 184 days of the Frequencies prior to reactor startup, 12 hours after reducing power below P-10, and four hours after reducing power below P-6, as discussed below. 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 thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup, 12 hours after reducing power below P-10, and four hours after reducing power below P-6. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

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 12 hour or 4 hour limit, as applicable. These time limits are reasonable, based on operating experience, 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 the periods discussed above. 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 the performance of a TADOT. 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 from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

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 DCPP setpoint methodology. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

Whenever an RTD is replaced in Functions 6, 7, or 14, the next required CHANNEL CALIBRATION of the RTDs 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.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. The CHANNEL CALIBRATION for the power range nuclear instruments includes a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP, and a test that shows allowed variances of detector voltage do not effect detector operation. The CHANNEL CALIBRATION for the intermediate range nuclear instruments includes a test that shows allowed variances of detector voltage do not effect detector operation. The CHANNEL CALIBRATION for the source range nuclear instruments includes a periodic test that optimizes detector high voltage and a conditional test for establishing baseline channel settings after maintenance. The baseline test includes obtaining detector high voltage and discriminator bias curves and using this data to evaluate detector and channel settings based on manufacturers' recommendations and industry operating experience.

This SR is modified by three Notes. Note 1 state that neutron detectors are excluded from the CHANNEL CALIBRATION. Note 2 states that the test shall include verification that the time constants are adjusted to the prescribed values where applicable. Note 3 states that, prior to entry into MODE 2 or 1, the power and intermediate range detector plateau voltage verification (as described above) is not required to be current until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 95% RTP. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to perform a meaningful detector plateau voltage verification. The allowance of 72 hours after equilibrium conditions are attained at the testing plateau provides sufficient time to allow power ascension testing to be conducted in a controlled and orderly manner at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE for subsequent use. The source range curves are obtained as required under the conditions that apply during a plant outage.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The conditions for obtaining the source range curves and for verifying the power and intermediate range detector operation are described above. The other remaining portions of the CHANNEL CALIBRATIONS may be performed either during a plant outage or during plant operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.12

SR 3.3.1.12 is the performance of a CHANNEL CALIBRATION of the seismic trip. For function 22, Seismic Trip, the calibration shall encompass, as a minimum, the sensor relays, the SSPS, and associated required alarms. Since it is impractical to routinely remove and ship the seismic trigger packages to an offsite facility to verify calibration on a shaker table, the sensors shall be verified by introducing a known acceleration to voltage relationship to the sensor and verifying the proper action, in accordance with the manufacturers recommendations.

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.

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, Seismic Trip and the SI Input from ESFAS. The Manual Reactor Trip test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. Breaker actuation is verified using the local indicator since physical verification of the main contacts is not practical. This is acceptable based on breaker design and industry operating and maintenance experience. The Seismic Trip TADOT shall, as a minimum, verify the OPERABILITY of the channel from the seismic sensor relays to the input logic of the SSPS. The remainder of the channel is tested under the SR 3.3.1.5 or 3.3.1.12 requirements.

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 from the TADOT. The Functions affected have no setpoints associated with them except for the Seismic Trip that is calibrated by SR 3.3.1.12.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. This TADOT is performed prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.16

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 and the individual functions requiring RESPONSE TIME verification are included in Equipment Control Guideline (ECG) 38.1. 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. 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.

The response time testing for the SG water level low-low does not include trip time delays. Response times include the transmitters, Eagle-21 process protection cabinets, solid state protection system cabinets, and actuation devices only. This reflects the response times necessary for THERMAL POWER in excess of 50 percent RTP. For those functions without a specified response time, SR 3.3.1.16 is not applicable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

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 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) inplace, 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. 8) 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,” provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time.” The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and reverified following maintenance work 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 response time may be verified for components that replace the components that were previously evaluated in Ref. 8 and Ref. 27, provided that the components have been evaluated in accordance with the NRC approved methodology as discussed in Attachment 1 to TSTF-569, “Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing,” (Ref. 34).

For Westinghouse supplied replacement SSPS printed circuit boards (PCBs), Westinghouse has determined that the bounding times and conclusions made in WCAP-14036-P-A apply to the worst-case combination of the new-design PCBs and the original (replaced) PCBs. This applies to reactor trip and safeguards (ESF) functions. Refer to Reference 32, Section 10, for more information.

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 3.3.1.16 (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. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. The source range preamplifiers are also excluded. This is acceptable because the principles of operation of the preamplifier have been evaluated and a determination made that there are no credible failure mechanisms that could affect response time that would not be detected during routine testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input to the first electronic component in the channel, exclusive of the preamplifier.

REFERENCES

1. UFSAR, Chapter 7.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. IEEE Std. 279-1971.
5. 10 CFR 50.49.
6. Blank
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. WCAP 13632 - PA-1, Rev. 2 "Elimination of Pressure Sensor Response Time Testing Requirements."
9. UFSAR, Sections 9.2.7 and 9.2.2.
10. UFSAR, Sections 10.3 and 10.4
11. UFSAR, Section 8.3.
12. DCM S-38A, "Plant Protection System"
13. WCAP-13878, "Reliability of Potter & Brumfield MDR Relays", June 1994.
14. WCAP-13900, "Extension of Slave Relay Surveillance Test intervals", April 1994.
15. WCAP-14117, "Reliability Assessment of Potter and Brumfield MDR Series Relays."
16. WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases," Revision 1, January 1978.

(continued)

BASES

REFERENCES (continued)

17. WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems, Diablo Canyon Units 1 and 2, 24 Month Fuel Cycle Evaluation and Replacement Steam Generator," September 2007.

18. NSP-1-20-13F Unit 1 "Turbine Auto Stop Low Oil Pressure."

19. NSP-2-20-13F Unit 2 "Turbine Auto Stop Low Oil Pressure."

20. J-110 "24 Month Fuel Cycle Allowable Value Determination / Documentation and ITDP Uncertainty Sensitivity."

21. IEEE Std. 338-1977.

22. License Amendment 61/60, May 23, 1991.

23. Westinghouse Technical Bulletin ESBU-TB-92-14-R1, "Decalibration Effects of Calorimetric Power Measurements on the NIS High Power Reactor Trip at Power Levels less than 70% RTP," dated February 6, 1996.

24. DCPP NSSS Calculation N-212, Revision 1.

25. License Amendments 157/157, June 2, 2003.

26. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.

27. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," October 1998.

28. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

29. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.

30. WCAP-11394-P-A, "Methodology For The Analysis of the Dropped Rod Event," January, 1990

31. License Amendments 205/206, April 29, 2009

32. WCAP-16769-P Revision 1, "Westinghouse SSPS Universal Logic Board Replacement Summary Report 6D30225G01/G02/G03/G04," July 2008.

33. WCAP-12472-P-A, Addendum 4, Revision 0, "BEACON Core Monitoring and Operations Support System," September 2012

34. Attachment 1 to TSTF-569, "Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing," August 2019.

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.

For Function 5.b in Technical Specification (TS) Table 3.3.2-1, this is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the ESFAS, as well as specifying Limiting Conditions for Operations on other system parameters and equipment performance. The subset of LSSS that directly protect against violating the reactor core and Reactor Coolant System (RCS) pressure boundary safety limits (SL) during anticipated operational occurrences (AOOs) are referred to as SL-LSSS.

The next four paragraphs apply only to Function 5.b in TS Table 3.3.2-1.

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

The Nominal Trip Setpoint (NTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit, and thus ensuring that the SL would not be exceeded. As such, the NTSP 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 NTSP ensures that SLs are not exceeded. As such, the NTSP meets the definition of an SL-LSSS (Ref. 19).

(continued)

BASES

BACKGROUND (continued)

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 functions(s)." Use of the NTSP to define OPERABILITY in TS 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 TS 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 NTSP 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 NTSP, 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 NTSP to account for further drift during the next surveillance interval.

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. The Allowable Value (AV) specified in Table 3.3.2-1 is the least conservative value of the as-found setpoint that channel can have when tested, such that a channel is OPERABLE if the as-found setpoint is conservative with respect to the AV during the CHANNEL OPERATIONAL TEST (COT). As such, the AV differs from the NTSP by an amount greater than or equal to the expected instrument channel uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will ensure that an SL is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. Note that, although the channel is OPERABLE under these circumstances, the NTSP must be left adjusted to a value within the as-left tolerance, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned (as-found criteria). If the actual setting of the device is found to be non-conservative with respect to the AV, the device would be considered inoperable. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

(continued)

BASES

BACKGROUND (continued)

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 50.67 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 occurrence. Meeting the acceptable consequences for that event is considered having acceptable consequences for that event. However, these values and their associated NTSPs are not considered to be LSSS as defined in 10 CFR 50.36.

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 digital 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 residual heat removal pump trip or refueling water storage tank level-low signal is not processed by the SSPS. The associated relays are located in the residual heat removal pumps control system.

(continued)

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 Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

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.

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

(continued)

BASES

BACKGROUND

Signal Processing Equipment (continued)

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. In the case of the Digital Feedwater Control System (DFWCS), the median/signal select (MSS) feature prevents control/protection interaction even though there are only three inputs and 2-out-of-3 logic. 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 2.

The channels are designed such that testing required to be performed at power may be accomplished without causing an ESF actuation. The Process Protection System is designed to permit any one channel to be tested and maintained at power in a bypass mode.

If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room as required by applicable codes and standards. As an alternate to testing in the bypass mode, testing in the trip mode is also possible and permitted.

(continued)

BASES

BACKGROUND (continued)

Trip Setpoints and Allowable Values

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the two-sided tolerance band for calibration accuracy.

The Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 2. 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 Trip Setpoints and Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems Diablo Canyon Units 1 & 2, 24 Month Fuel Cycle and Replacement Steam Generator Evaluation," September 2007 (Ref. 12), calculation J-54 (Ref. 13) and calculation J-110 (Ref. 14). Interlock setpoints are nominal values provided in the PLS (Westinghouse Precautions Limitations and Setpoints) and their allowable values are calculated in Calculation J-110 Rev. 7 (Ref. 14). For Function 5.b in TS Table 3.3.2-1, the magnitudes of these uncertainties are factored into the determination of the NTSP and corresponding AV. The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for Rack Drift and Rack Measuring and Test Equipment uncertainties. The calibration tolerance, after conversion, should correspond to the rack comparator setting accuracy defined in the latest setpoint study. For Function 5.b in TS Table 3.3.2-1, the AV serves as the Technical Specification OPERABILITY limit for purposes of the COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint is conservative with respect to the Allowable Value, the bistable is considered OPERABLE. For Function 5.b in TS Table 3.3.2-1, note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to within the established as-left criteria and confirmed to be operating within the statistical allowances of the uncertainty terms assigned.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Since there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift in excess of the allowance that is more than occasional may be indicative of more serious problems and warrants further investigation.

Setpoints in accordance with the Allowable Value and in conjunction with the use of as-found and as-left tolerances 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. For Function 5.b in Table 3.3.2-1, note that the AV is the least conservative value of the as-found setpoint that a channel can have during a periodic CHANNEL CALIBRATION or COT that requires trip setpoint verification.

Certain channels can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements for Reference 2. 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.

The Trip Setpoints and Allowable Values listed in Table 3.3.2-1 are based on the methodology described in Reference 12, 13, and 14, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. In the event a channel's setpoint is found nonconservative with respect to the specified Trip Setpoint, but more conservative than the Allowable Value, the setpoint must be adjusted consistent with the Trip Setpoint value. When a channel's Trip Setpoint is nonconservative with respect to the Allowable Value, declare the channel inoperable and apply the applicable ACTION statement until the channel is returned to OPERABLE status with its Setpoint adjusted consistent with the Trip Setpoint value. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

The ESFAS Trip Setpoints may be administratively redefined in the conservative direction for several reasons including startup, testing, process error accountability, or even a conservative response for equipment malfunction or inoperability. ESFAS functions are not historically redefined at the beginning of each cycle for purposes of startup or testing as several reactor Trip functions are. However, calibration to within the defined calibration tolerance of an administratively redefined, conservative Trip Setpoint is acceptable. Redefinition at full power conditions for these functions is expected and acceptable.

(continued)

BASES

BACKGROUND (continued)

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 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.

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BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. Functions 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. For Function 5.b in TS Table 3.3.2-1, however, qualitatively credited or backup functions are not SL-LSSS for reactor fuel/cladding or RCS pressure boundary SLs. 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).

For Function 5.b in TS Table 3.3.2-1, ESFAS Actuation setpoints that directly protect against violating the reactor core or RCS pressure boundary SLs during AOOs are SL-LSSS. The ESFAS interlocks allow ESFAS functions to be blocked for shutdown operations and automatically unblocked for the ESFAS function when the plant is started up. The ESFAS interlocks do not function as part of the automatic actuation system and are not modeled in the safety analysis. Therefore, permissives and interlocks are not considered to be SL-LSSS.

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. For Function 5.b in Table 3.3.2-1, a channel is OPERABLE with an NTSP value outside its calibration tolerance band provided the trip setpoint as-found value is conservative with respect to its associated AV and provided the NTSP as-left value is adjusted to a value within the calibration tolerance band of the NTSP. A trip setpoint may be set more conservative than the NTSP as necessary in response to plant conditions.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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, cut-out 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. <u>Safety Injection</u>

   Safety Injection (SI) provides two primary functions:

   1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and
   2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

   These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

   - Phase A Isolation;
   - Containment Ventilation Isolation;
   - Reactor Trip;
   - Turbine Trip from Reactor Trip with P-9;
   - Feedwater Isolation and Feedwater Pump Turbine Trip;
   - Start of motor driven auxiliary feedwater (AFW) pumps;
   - Control room ventilation to pressurization mode via Phase A isolation, and Auxiliary Building to "Building and Safeguards or Safeguards Only" mode;
   - Start of the diesel generators (DGs) and transfer to the startup bus;
   - Start of the containment fan cooler units (CFCUs) in low speed;
   - Start of the component cooling water and auxiliary salt water pumps;
   - Input to containment spray pump and discharge valve auto start (with containment spray signal);
   - Isolate SG sample blowdown lines.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

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;
- Transfer of the control room ventilation to ensure habitability;
- Transfer of the auxiliary building ventilation to ensure ventilation cooling to the ESF pump rooms;
- Start of the DGs to compensate for a possible loss of offsite power (LOOP); and
- Start of the components associated with the accident heat removal systems.

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 control switch and the interconnecting wiring to the actuation logic cabinet. Each control switch actuates both trains. This configuration does not allow testing at power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (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, 3, and 4. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation control switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection-Containment Pressure-High

This signal provides protection against the following accidents:

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

Containment Pressure-High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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, 3, and 4 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection-Pressurizer Pressure-Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- A spectrum of rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Pressurizer pressure provides both control and protection functions: input to the Pressurizer Pressure Control System, reactor trip, and SI. Therefore, the actuation logic must be able to withstand both an input failure to control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four logic.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-11 interlock and below P-11 interlock, unless the Safety Injection - Pressurizer Pressure - Low Function is blocked) 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 interlock. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection-Steam Line Pressure

(1) Steam Line Pressure-Low

Steam Line Pressure-Low provides protection against the following accidents:

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

Steam Line Pressure-Low provides input to the DFWCS functions. The MSS function prevents the excursion of one of the inputs from causing a process disturbance that would require protective action from the remaining channels on the affected steam line. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

With some transmitters located inside the penetration area, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

This Function is anticipatory in nature and has a lead/lag ratio of 50/5.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Safety Injection-Steam Line Pressure (continued)

Steam Line Pressure-Low must be OPERABLE in MODES 1, 2, and 3 (above P-11 interlock and below P-11 interlock, unless the Safety Injection - Steam Line Pressure - Low Function is blocked) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. 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) Not used

f, g. Not used

2. Containment Spray

Containment Spray coincident with an SI signal provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;
2. Reduces the amount of radioactive iodine in the containment atmosphere; and
3. Adjusts the pH of the water in the containment recirculation sump after a large break LOCA.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Containment Spray (continued)

The containment spray actuation signal coincident with SI starts the containment spray 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 containment spray pumps and mixed with a sodium hydroxide solution from the spray additive tank. When the RWST reaches the low low level setpoint, the spray pumps are manually tripped. Spray flow can then be shifted to the RHR system if continued containment spray is required. Containment spray is actuated by Containment Pressure-High High coincident with an SI signal.

a. Containment Spray-Manual Initiation

The operator can manually initiate containment spray from the control room if an SI signal is present by simultaneously turning both Containment Isolation Phase "B" (containment spray) actuate Trains A & B switches. Because an inadvertent actuation of containment spray could have such serious consequences, two switches must be turned simultaneously and an SI signal must be present to initiate containment spray. 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. Note that Manual Initiation of containment spray also actuates Phase B containment isolation and CVI.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Containment Spray-Automatic Actuation Logic and Actuation Relays (continued)

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

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 Trip Setpoint reflects only steady state instrument uncertainties.

This is one of the 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.

The logic configuration is a two-out-of-four. This configuration is called the Containment Pressure-High High Setpoint. Additional redundancy is warranted because this Function is energize to trip. Containment Pressure- High High must be OPERABLE in MODES 1, 2, 3, and 4 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 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.

(continued)

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 (CCW) to the RCP thermal barrier heat exchangers and RCP lube oil coolers/RV support coolers, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW is required to support RCP operation, not isolating CCW on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CCW on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually via the automatic actuation logic. 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. Note that manual actuation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

The Phase B signal isolates CCW to the RCP thermal barrier heat exchangers and RCP lube oil coolers/RV support coolers. 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 CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Containment Isolation (continued)

Therefore, the combination of CCW System design and Phase B isolation ensures the CCW System is not a potential path for radioactive release from containment except for leakage in a containment fan cooler coil following an accident. The radioactivity associated with the leak would actuate the CCW system radiation monitor. The monitor in turn would annunciate in the control room and close the vent valve located just up-stream of the CCW surge tank back-pressure regulator to prevent the regulator from venting after sensing high tank pressure. The operator could then take appropriate action to isolate the failed component. In addition to the radiation monitoring system, the condition of high level and high pressure in the surge tank would be annunciated as the tank filled. If the in-leakage continues after the vent is closed, the surge tank pressure would increase until the high surge tank pressure alarm annunciated and the relief valve setpoint was reached. The relief valve on the surge tank will protect the surge tank from overpressurization. Relief valve discharge from the CCW surge tank is routed to the skirted area under the surge tank, which then enters a floor drain routed to the auxiliary building sump.

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 and containment spray must have been actuated. RCP operation will no longer be required and CCW to the RCPs is, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW 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 are operated 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. Note that manual initiation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Containment Isolation (continued)

(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.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, 3, and 4, when there is a potential for an accident to occur. Because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation control switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation-Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

b. Containment Isolation-Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2). 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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, 3, and 4 when there is a potential for an accident to occur. Because of the large number of components actuated on a Phase B containment isolation, actuation is simplified by the use of the manual actuation switches. 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 isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the steam lines depressurize.

a. Steam Line Isolation-Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room via an individual switch for each valve. The LCO requires one channel per valve to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Steam Line Isolation (continued)

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 MSIVs are closed and de-activated, i.e. actions are taken to ensure the values cannot be inadvertently opened. 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-High-High

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to limit the mass and energy release to containment from a single SG. The transmitters (d/p cells) are located outside containment with the sensing line (high pressure side of the transmitter) located inside containment. Containment Pressure — High-High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. However, for enhanced reliability, this Function was designed with four channels and a two-out-of-four 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-High-High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated, i.e., actions are taken to assure that the valve cannot be inadvertently opened.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Steam Line Isolation-Containment Pressure-High-High (continued)

In MODE 4, the increase in containment pressure following a pipe break would occur over a relatively long time period such that manual action could reasonably be expected to provide protection and ESFAS Function 4.d need not be OPERABLE. 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-High-High setpoint.

d. Steam Line Isolation-Steam Line Pressure

(1) Steam Line Pressure-Low

Steam Line Pressure-Low provides closure of the MSIVs in the event of an SLB to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. This Function provides closure of the MSIVs in the event of a feed line break to ensure a supply of steam for the turbine driven AFW pump. Steam Line Pressure-Low was discussed previously under SI Function 1.e.1.

Steam Line Pressure-Low Function must be OPERABLE in MODES 1, 2, and 3 (above P-11 interlock and below P-11 interlock if the Steam Line Pressure - Low function is not blocked), with any main steam valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11 when blocked, an inside containment SLB will be terminated by automatic actuation via Containment Pressure-High-High. Stuck valve transients and outside containment SLBs will be terminated by the Steam Line Pressure-Negative Rate-High signal for Steam Line Isolation below P-11 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed and de-activated, i.e., actions are taken to ensure the valves cannot be inadvertently opened. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Steam Line Isolation-Steam Line Pressure (continued)

(2) Steam Line Pressure-Negative Rate-High

Steam Line Pressure-Negative Rate-High provides closure of the MSIVs for an SLB when less than the P-11 setpoint, to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. When the operator manually blocks the Steam Line Pressure-Low main steam isolation signal when less than the P-11 setpoint, the Steam Line Pressure-Negative Rate-High signal is automatically enabled. Steam Line Pressure-Negative Rate-High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy requirements with a two-out-of-three logic on each steam line.

Steam Line Pressure-Negative Rate-High must be OPERABLE in MODE 3 (trip coincidence 2 per steam line in any steam line) when less than the P-11 setpoint, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In MODES 1 and 2, and in MODE 3, when above the P-11 setpoint, this signal is automatically disabled and the Steam Line Pressure-Low signal is automatically enabled. When below P-11, this Function is automatically blocked when Safety Injection on Steam Line Pressure-Low is not blocked. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated, i.e., actions are taken to ensure the valves cannot be inadvertently opened. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to have an SLB or other accident that would result in a release of significant enough quantities of energy to cause a cooldown of the RCS.

While the transmitters may experience elevated ambient temperatures due to an SLB, the trip function is based on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

e, f. Not used

g. Not used

h. Not used

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Feedwater Isolation

The primary functions of the Feedwater Isolation signals are to stop the excessive flow of feedwater into the SGs. This Function is 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 MFW pumps;
- Initiates feedwater isolation; and
- Shuts the MFW regulating valves and the bypass feedwater regulating valves coincident with P-4.

This Function is actuated by SG Water Level-High High or by an SI signal. In the event of SI, the unit is taken off line and the MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously.

a. 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. 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. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Thus, three OPERABLE channels (narrow range instrument span for each generator) are required to satisfy the requirements with a two-out-of-three logic and a median signal selector is provided to prevent control and protection function interactions.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Feedwater Isolation (continued)

c. Feedwater Isolation-Safety Injection

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.

Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 except when all MFIVs, MFRVs, and associated bypass valves are closed and de-activated or isolated by a closed manual valve when the MFW System is in operation and the turbine generator may be in operation. In MODES 3, 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 condensate storage tank (CST) . The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater - Manual Initiation

Manual initiation of Auxiliary Feedwater can be accomplished from the Control Room. Each of the three AFW pumps has a switch for manual initiation. The LCO requires three channels to be OPERABLE.

b. Auxiliary Feedwater-Automatic Actuation Logic and Actuation Relays (Solid State Protection System)

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

c. Not used

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Auxiliary Feedwater (continued)

d.1) 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. Therefore, the actuation logic must be able to withstand both an input failure to the control system which may then require a protection function actuation and a single failure in the other channels providing the protection function actuation. Thus, three OPERABLE channels (narrow range instrument span each generator) are required to satisfy the requirements with two-out-of-three logic and a median signal selector is provided for level control.

This function is actuated on two out of three low-low water level signals occurring in any steam generator. If a low-low water level condition is detected in one steam generator, signals are generated to start the motor driven auxiliary feedwater pumps. If a low-low water level condition is detected in two or more steam generators, a signal is generated to start the turbine driven auxiliary feedwater pump as well.

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.

d.2) SG Water Level - Low Low Trip Time Delay (TTD)

The signals to start auxiliary feedwater pumps are delayed through the use of a Trip Time Delay (TTD) system for reactor power levels below 50.7% of RTP. Low-low water level in any protection set in any steam generator will generate a signal which starts an elapsed time trip delay timer.

Table 3.3.2-1 uses the term channel when designating the required number instrument channels to meet the LCO for a function. In the case of the TTD system, each channel is not actually an instrument channel, but imbedded software, which acts as a processor.

Two of the four TTD processors provide an output to each of the four-steam generators low-low level trip functions. The other two TTD processors each provide inputs to the low-low level steam generators trip functions for two of the four steam generators.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d.2) SG Water Level - Low Low Trip Time Delay (TTD) (continued)

The steam generator water level-low low trip requires two trip signals from any one steam generator. Together the four TTD processors provide the low power time delay for the three outputs to each of the four steam generator low-low level trip functions.

The allowable trip time delay is based upon the prevailing power level at the time the low-low level trip setpoint is reached. If power level rises after the trip time delay setpoints have been determined, the trip time delay is re-determined (i.e., decreased) according to the increase in power level. However, the trip time delay is not changed if the power level decreases after the delay has been determined. The use of this delay allows added time for natural steam generator level stabilization or operator intervention to avoid an inadvertent protection system actuation.

e. Auxiliary Feedwater-Safety Injection

An SI signal starts the motor 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.

f. Not used

Functions 6.a, 6.b, and 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 operating SG will cause the motor driven AFW pumps to start.

The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level-Low Low in any two operating SGs will cause the turbine driven pumps to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

g. Auxiliary Feedwater-Undervoltage Reactor Coolant Pump

A loss of power on the buses that provide power to the RCPs provides indication of a pending loss of RCP forced flow in the RCS during MODE 1 operation above P-7. Below P-7, this ESFAS and RTS function is blocked since there is insufficient heat to be concerned about DNB. The Undervoltage RCP Function senses the voltage upstream of each RCP breaker. A loss of power on two RCPs results in an anticipatory start of the turbine driven AFW pump 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. This anticipatory start is not credited in the accident analyses.

h. Not used

Function 6.g must be OPERABLE in MODE 1. 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 2, 3, 4, and 5, the pump trip is not indicative of a condition requiring automatic AFW initiation of the TDAFW pump. No other anticipatory start signals are necessary for the TDAFW pump, only low level in 2 of 4 SGs.

i. Not used

7. Residual Heat Removal Pump Trip on Refueling Water Storage Tank Level - Low

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 manually switched to the containment recirculation sump. This pump trip feature is blocked if the RHR pumps are already taking suction from the containment recirculation sump. The low head RHR pumps draw the water from the containment recirculation sump.

The RHR pumps pump the water through the RHR heat exchanger, inject the water back into the RCS, and supply the cooled water to the other ECCS pumps. Switchover from the RWST to the containment sump must occur before the RWST empties to prevent damage to the RHR 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 RHR 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Residual Heat Removal Pump Trip on Refueling Water Storage Tank Level - Low (continued)

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. The RHR pump trip on RWST low level 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 three level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-three logic is adequate to initiate the protection function actuation.

The Allowable Value/Trip Setpoint upper limit is selected to ensure adequate water inventory in the containment sump to provide RHR pump suction. The high limit also ensures enough borated water is injected to ensure the reactor remains shut down.

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 trip setpoint reflects only steady state instrument uncertainties.

This Function 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. This Function is 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 prevented from actuating to prevent inadvertent overpressurization of unit systems or are not required to be OPERABLE.

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.

(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

The P-4 interlock is enabled when a reactor trip breaker (RTB) and its associated bypass breaker is open. This Function allows operators to manually block reactuation 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. The functions of the P-4 interlock are:

- Trip the main turbine;
- Isolate MFW with coincident low $T_{avg} \leq 554°F$;
- Allows manual block of the automatic reactuation of SI ;
- Transfer the steam dump from the load rejection controller to the plant trip controller; and
- Prevent opening of the MFW Regulating valves or bypass valves if they were closed on SI or high SG Water Level.

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. To avoid such a situation, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system.

None of the noted Functions serves a mitigation function in the unit licensing basis safety analyses. Only the turbine trip Function is explicitly assumed since it is an immediate consequence of the reactor trip Function. Neither turbine trip, nor any of the other four Functions associated with the reactor trip signal, is required to show that the unit licensing basis safety analysis acceptance criteria are met.

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable trip setpoint with which to associate a Trip Setpoint and Allowable Value.

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because the main turbine, the MFW System, and the Steam Dump System are not in operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Engineered Safety Feature Actuation System Interlocks (continued)

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 or main steam line isolation. 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 and Steam Line Pressure-Low SI signals and the Steam Line Pressure-Low steam line isolation signal (previously discussed). When the Steam Line Pressure-Low steam line isolation signal is manually blocked, a main steam isolation signal on Steam Line Pressure-Negative Rate-High is enabled. This provides protection for an SLB by closure of the MSIVs. With two-out-of-three pressurizer pressure channels above the P-11 setpoint, the Pressurizer Pressure-Low and Steam Line Pressure-Low SI signals and the Steam Line Pressure-Low steam line isolation signal are automatically enabled. The operator can also enable these trips by use of the respective manual reset switches. When the Steam Line Pressure-Low steam line isolation signal is enabled, the main steam isolation on Steam Line Pressure-Negative Rate-High is disabled. The Trip Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

c. Not used

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

(continued)

BASES

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

With an ESFAS Instrumentation Channel or Interlock Trip Setpoint less conservative than the value shown in the Trip Setpoint column but more conservative than the value shown in the Allowable Values column of Table 3.3.2-1, adjust the Setpoint consistent with the Trip Setpoint value.

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.

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.

<u>A.1</u>

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.

(continued)

BASES

ACTIONS (continued)

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B 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 and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each 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 overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 4 within an additional 6 hours (60 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.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 20). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 20, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS (continued)

Required Action B.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

C.1, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 17. 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 overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 4 within an additional 6 hours (36 hours total time).

(continued)

BASES

ACTIONS (continued)

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

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 20). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 20, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

Consistent with the requirement in Reference 17 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included. These restrictions do not apply when a logic train is being tested under the 4-hour bypass Note of Condition C. When a logic train is inoperable for maintenance, the following should not be scheduled:

(continued)

BASES

ACTIONS (continued)

- Activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip (to preserve ATWS mitigation capability).
- Activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable (to preserve reactor trip and safeguards actuation capability).
- Activities that prevent maintaining one complete emergency core cooling system train that can be actuated automatically (to preserve LOCA mitigation capability).
- Activities on electrical systems (e.g., AC and DC power) and cooling systems (ASW and CCW) that support the systems or functions listed above.

Since Condition C is typically entered due to equipment failure, it follows that some of the above restrictions may not be met at the time of Condition C entry. If this situation were to occur during the 24-hour Completion Time of Required Action C.1, the configuration risk management program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition C or fully implement the restrictions.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 8) that 4 hours is the average time required to perform train surveillance.

(continued)

BASES

ACTIONS (continued)

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

Condition D applies to:

- SI - Pressurizer Pressure — Low;
- SI - Steam Line Pressure — Low;
- Steam Line Isolation - Steam Line Pressure — Negative Rate — High;
- Steam Line Isolation - Steam Line Pressure — Low; and
- Auxiliary Feedwater - SG Water level — Low Low;

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic (excluding pressurizer pressure - low which is two-out-of-four due to its control input function). Therefore, failure of one channel places the Function in a two-out-of-two configuration. The inoperable channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements. Since pressurizer pressure is used for control and SSPS input, its coincidence is two-out-of-four to provide to required reliability and redundancy. Failure of one channel places the function in a two-out-of-three configuration. The inoperable channel must be placed in the tripped condition to place the Function in a one-out-of-three configuration that satisfies the reliability and redundancy requirements.

(continued)

BASES

ACTIONS

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

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 for Function 1.d that allows the inoperable channel and/or one additional channel to be tested with one channel in bypass and one channel in trip, or with both the inoperable and the additional channel in bypass for up to 12 hours for surveillance testing. For Functions 1.e, 4.d(1), 4.d(2) and 6.d(1), the Note allows the inoperable channel and/or one additional channel to be tested with one channel in bypass and one channel in trip for up to 12 hours for surveillance testing. Function 1.d is a two-out-of-four trip logic and Functions 1.e, 4.d(1), 4.d(2) and 6.d(1) are two-out-of-three logic actuation logics. The allowed testing configurations provide flexibility for testing, while assuring that during testing no configuration will cause an inadvertent actuation of the function or keep a valid signal from actuating the function as it was designed. 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 17. This note is not intended to allow simultaneous testing of coincident channels on a routine basis.

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

Condition E applies to:

- Steam Line Isolation - Containment Pressure - High-high

This signal does not 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 of the Containment Pressure input 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.

(continued)

BASES

ACTIONS

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

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 72 hours allowed to restore the channel to OPERABLE status or to place it in the bypass condition is justified in Reference 17. 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 the inoperable channel to be tested in bypass for up to 12 hours for surveillance testing. In addition, the Note allows the inoperable channel and one additional channel to be tested in bypass for up to 12 hours for surveillance testing **only** if the Function 1.c channel associated with the inoperable channel is in trip during the testing. The 12 hour time limit is justified in reference 17.

This function is a two-out-of-four actuation logic and three of its channels are contained on common control channels with three other functions and the fourth channel is on a common control channel with two other functions. As a result, if a common control channel is inoperable then one channel from each of its contained functions is inoperable. Three of the common control channels each contain a channel from the Safety Injection Containment Pressure – High (Function. 1.c). Function 1.c, is a two-out-of-three logic, which requires an inoperable channel to be placed in trip to continue operability and only one channel at a time is allowed to be bypassed for testing.

(continued)

BASES

ACTIONS

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

As a result, for the three common control channels that include a Function 1.c channel the testing of a second common control channel in bypass requires verification that the Function 1.c channel on the inoperable common control channel is in trip. Otherwise no second common control channel can be tested in bypass. However, if the fourth common control channel is the inoperable channel, then with that common control channel in bypass, any one of the other three common control channels may be tested in bypass without placing the associated Function 1.c, channel in trip. Placing a second channel in the bypass condition for up to 12 hours for testing purposes is acceptable based on Reference 17. The allowed testing configurations provide flexibility for testing, while assuring that during testing no configuration will cause an inadvertent actuation of the function or keep a valid signal from actuating the function or an associated function as designed. This note is not intended to allow simultaneous testing of coincident channels on a routine basis.

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

Condition F applies to the P-4 Interlock.

For the P-4 Interlock Function, this action addresses the train orientation of the SSPS. If a train is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of this Function, 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 function noted above.

(continued)

BASES

ACTIONS (continued)

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 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 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 17. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

Consistent with the requirement in Reference 17 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included. These restrictions do not apply when a logic train is being tested under the 4-hour bypass Note of Condition G. When a logic train is inoperable for maintenance, the following should not be scheduled:

- Activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip (to preserve ATWS mitigation capability).
- Activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable (to preserve reactor trip and safeguards actuation capability).
- Activities that prevent maintaining one complete emergency core cooling system train that can be actuated automatically (to preserve LOCA mitigation capability).
- Activities on electrical systems (e.g., AC and DC power) and cooling systems (ASW and CCW) that support the systems or functions listed above.

(continued)

BASES

ACTIONS

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

Since Condition G is typically entered due to equipment failure, it follows that some of the above restrictions may not be met at the time of Condition G entry. If this situation were to occur during the 24-hour Completion Time of Required Action G.1, the configuration risk management program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition G or fully implement the restrictions.

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 Automatic Actuation Logic and Actuation Relays for the Feedwater Isolation Function.

This action addresses the train orientation of the SSPS and the master and slave relays for this Function. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 17. 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. 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. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 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.

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

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 train surveillance.

I.1 and I.2

Condition I applies to Auxiliary Feedwater - Undervoltage Reactor Coolant Pump

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the function is then in a partial trip condition where one additional tripped channel will result in actuation. The 72 hour Completion Time is justified in Ref. 17. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours, requires the Unit to be placed in MODE 2 with in the following 6 hours. Six hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner without challenging unit systems. In MODE 2, this Function is 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. In accordance with WCAP 10271, very specific circumstances are related to the use of this bypass condition for ESFAS Functions 6.g. Since this channel is not designed with Bypass-capable logic that meets the requirements of IEEE 279, the provisions for bypass only apply to a specific type of channel failure. To apply, the channel must fail in such a way that it does not trip the bistables. With this type of failure, the channel may be returned to service and considered "bypassed" under this Note. Specifically, the bypass condition is the state when a failed channel is taken out of the forced "tripped" state and placed in operation. Due to the failed nature of the channel, the channel cannot be assumed to be OPERABLE, and is therefore considered to be in a state of bypass when the channel failure is such that its bistables are not tripped. The provisions of WCAP 10271 specifically prohibit the use of jumpers or lifted leads to bypass this channel. In this configuration, a second channel can be tested with the channel in the tripped mode without completing ESFAS logic. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 17.

(continued)

BASES

ACTIONS (continued)

J.1 and J.2

Condition J applies to the Feedwater Isolation Actuation signal resulting from Steam Generator Level - High-High (P-14).

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two logic will result in actuation. The 72-hour Completion Time is justified in Reference 17. Failure to restore the inoperable channel to OPERABLE status or place in the tripped condition within 72 hours requires the unit to be placed in MODE 3 within the following 6 hours. Six 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, this Function is no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel and/or one additional channel to be tested with one channel in bypass and one channel in trip for up to 12 hours for surveillance testing. This Function is a two-out-of-three actuation logic and the allowed testing configurations provide flexibility for testing, while assuring that during testing no configuration will cause an inadvertent actuation of the function or keep a valid signal from actuating the function as it was designed. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 17. This note is not intended to allow simultaneous testing of coincident channels on a routine basis.

K.1.1, K.1.2, K.2.1 and K.2.2

Condition K applies to the Residual Heat Removal Pump Trip on RWST Level - Low. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass (cut-out) condition within 6 hours is sufficient to ensure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed low). Placing the out-of-service channel in cut-out removes that channel from the trip logic, similar to a bypass function. This provides a two-out-of-two trip logic from the remaining channels. The 6 hour Completion Time is justified in Reference 8. If the channel cannot be placed in the cut-out condition within 6 hours, and returned to an OPERABLE status within 48 hours, the unit must be brought to MODE 3 within 54 hours and MODE 5 within 84 hours. The allowed Completion Times for shutdown 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 pump trip function noted above.

(continued)

BASES

ACTIONS (continued)

L.1, L.2.1 and L.2.2

Condition L applies to the P-11 interlock.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The verification determination can be made by observation of the associated annunciator window(s). The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of these interlocks.

M.1, M.2, M.3.1 and M.3.2

Condition M applies to the Trip Time Delay (TTD) channels (processors) for the SG Water Level-Low Low actuation of the turbine-driven AFW pump and is required to be OPERABLE in MODES 1, 2 and 3. With one or more TTD channels (processors) inoperable or the RSC ΔT equivalent power input inoperable, 72 hours are allowed to adjust the threshold power level for no time delay to 0% RTP. This sets the TTD processor timer to zero seconds and effectively removes its input for the SG water level circuit. If the TTD timer processor cannot be set to zero seconds for a single SG water level control, then the affected SG water level low-low channel must be placed in trip. Only one SG water level low-low channel per generator can be placed in trip position without tripping the plant. The Completion Time of 72 hours is justified in Reference 17.

If the TTD threshold power for no time delay cannot be adjusted to 0% RTP (zero seconds time delay) or the single SG water level output channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in MODE 4 where these Functions are not required OPERABLE. A completion time of 78 hours is allowed to place the unit in MODE 3 and 84 hours for MODE 4. These completion times are reasonable, based on operating experience, to place the unit in MODE 4 from full power in an orderly manner and without challenging unit systems. In MODE 4 there are no analyzed transients requiring the use of the turbine-driven AFW pump.

(continued)

BASES

ACTIONS

M.1, M.2, M.3.1 and M.3.2 (continued)

The Required Actions have been modified by a note that allows the inoperable TTD channel (processor) and/or one additional TTD channel (processor) to be surveillance tested with the affected SG low-low water level channels for one TTD channel (processor) in bypass and the affected SG low-low water level channels for the other TTD channel (processor) in trip for up to 12 hours. The 12 hour time limit is justified in reference 17. This note is not intended to allow simultaneous testing of multiple TTD channels (processors) on a routine basis.

If Required Action M.1 is completed for an inoperable TTD processor, the affected SG low-low water level channels would still be operable in that a valid SG low-low water level trip function would not be delayed. With the inoperable TTD processor meeting this required action, the above note will still apply for the inoperable TTD processor and/or one additional TTD processor.

N.1 or N.2

Condition N applies to:

- Manual Initiation of Steam Line Isolation; and
- Manual Initiation of Auxiliary Feedwater.

If a channel is inoperable, 48 hours is allowed to return the channel to an 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 associated pump or valve shall be declared inoperable immediately and the REQUIRED ACTION of 3.7.5 or 3.7.2 as applicable complied with immediately.

O.1 or O.2.1 and O.2.2

Condition O applies to Safety Injection resulting from Containment Pressure - 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. Failure of one channel places the function in a two-out-of-two configuration since the trip coincidence is two-out-of-three. The inoperable channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

(continued)

BASES

ACTIONS

O.1 or O.2.1 and O.2.2 (continued)

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 78 hours and MODE 5 in 108 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, these functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be tested in bypass or with the inoperable channel in trip, one additional channel maybe tested in bypass for up to 12 hours while performing surveillance testing. This function is a two-out-of-three trip logic and the allowed testing configurations provide flexibility for testing, while assuring that during testing no configuration will cause an inadvertent actuation of the function or keep a valid signal from actuating the function as it was designed. 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 17. This note is not intended to allow simultaneous testing of coincident channels on a routine basis.

P.1 or P.2.1 and P.2.2

Condition P applies to:

Containment Spray - Containment Pressure - High-High.

Containment Isolation - Phase B Isolation - Containment Pressure - High-High

Neither 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. The containment spray signal is also interlocked with SI and will not initiate without simultaneous SI and containment spray signals.

(continued)

BASES

ACTIONS

<u>P.1 or P.2.1 and P.2.2</u> (continued)

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 72 hours allowed to restore the channel to OPERABLE status or to place it in the bypassed condition is justified in Reference 17.

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 78 hours, and MODE 5 in 108 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, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be tested in bypass for up to 12 hours for surveillance testing. In addition, the Note allows the inoperable channel and one additional channel to be tested in bypass for up to 12 hours for surveillance testing **only** if the Function 1.c channel associated with the inoperable channel is in trip during the testing.

This function is a two-out-of-four actuation logic and three of its channels are contained on common control channels with three other functions and the fourth channel is on a common control channel with two other functions. As a result, if a common control channel is inoperable then one channel from each of its contained functions is inoperable. Three of the common control channels each contain a channel from the Safety Injection Containment Pressure – High (Function. 1.c). Function 1.c, is a two-out-of-three logic, which requires an inoperable channel to be placed in trip to continue operability and only one channel at a time is allowed to be bypassed for testing. As a result, for the three common control channels that include a Function 1.c channel the testing of a second common control channel in bypass requires verification that the Function 1.c channel on the inoperable common control channel is in trip. Otherwise no second common control channel can be tested in bypass. However, if the fourth common control channel is the inoperable channel, then with that common control channel in bypass, any one of the other three common control channels may be tested in bypass without placing the associated Function 1.c, channel in trip.

(continued)

BASES (continued)

ACTIONS

P.1 or P.2.1 and P.2.2 (continued)

Placing a second channel in the bypass condition for up to 12 hours for testing purposes is justified in Reference 17. The allowed testing configurations provide flexibility for testing, while assuring that during testing no configuration will cause an inadvertent actuation of the function or keep a valid signal from actuating the function or an associated function as designed. This note is not intended to allow simultaneous testing of coincident channels on a routine basis.

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.

Agreement criteria are established in STP I-1A, 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2

SR 3.3.2.2 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. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.3 - Not used

SR 3.3.2.4

SR 3.3.2.4 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. The time allowed for the testing (4 hours) is justified in Reference 8. 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 COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found conservative with respect to the Allowable Values specified in Table 3.3.2-1.

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.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis (Ref. 8) when applicable.

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

The next two paragraphs apply only to Function 5.b, an SL-LSSS function, in TS Table 3.3.2-1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.5 (continued)

SR 3.3.2.5 for Function 5.b is modified by two notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the AV. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with safety analysis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. The performance of these channels will be evaluated under the Diablo Canyon Power Plant (DCPP) Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures, the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the SL and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable.

The second Note also requires that the NTSP and the methodologies for calculating the as-left and the as-found tolerances be in the Equipment Control Guidelines (ECGs).

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7 - Not used

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions (except AFW; refer to SR 3.3.2.13). Each Manual Actuation Function is tested up to, and including, the master relay coils. 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 for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.9

SR 3.3.2.9 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

Whenever an RTD is replaced in Function 6.d., the next required CHANNEL CALIBRATION of the RTDs 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.

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.

The next two paragraphs apply only to Function 5.b, an SL-LSSS function, in TS Table 3.3.2-1.

SR 3.3.2.9 for Function 5.b is modified by two notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the AV. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with safety analysis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. The performance of these channels will be evaluated under the DCPP Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures, the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the SL and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable.

The second Note also requires that the NTSP and the methodologies for calculating the as-left and the as-found tolerances be in the ECGs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.10

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 and the individual Functions requiring RESPONSE TIME Verification are included in ECG 38.2. 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 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 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) inplace, onsite, or offsite (e.g., vendor) test measurements, or 3) utilizing vendor engineering specifications. WCAP-13632-P-A, revision 2, "elimination of Pressure sensor

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.10 (continued)

Response time Testing requirements," dated January 1996, provides the basis and the methodology of 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," provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time." The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and reverified following maintenance work 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 response time may be verified for components that replace the components that were previously evaluated in Ref. 11 and Ref. 16, provided that the components have been evaluated in accordance with the NRC approved methodology as discussed in Attachment 1 to TSTF-569, "Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing," (Ref. 21).

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 650 psig in the SGs.

SR 3.3.2.11

SR 3.3.2.11 is the performance of a TADOT as described in SR 3.3.2.8, except that it is performed for the P-4 Reactor Trip Interlock. 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 Function tested has no associated setpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.12

SR 3.3.2.12 is the performance of an ACTUATION LOGIC TEST. This SR is applied to the RHR Pump Trip on RWST Level-Low actuation logic and relays which are not processed through the SSPS. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.13

SR 3.3.2.13 is the performance of a TADOT. This test is a check of the Manual Actuation Function for AFW. Each Manual Actuation Function is tested up to, and including, the master relay coils. 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 for manual initiation Functions. The manual initiation Functions have no associated setpoints.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 7.
3. UFSAR, Chapter 15.
4. IEEE Std.279-1971.
5. 10 CFR 50.49.
6. Blank
7. WCAP-13900, "Extension of Slave Relay Surveillance Test intervals", April 1994
8. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

(continued)

BASES

REFERENCES (continued)

9. WCAP-13878, "Reliability of Potter & Brumfield MDR Relays", June 1994.
10. WCAP-14117, "Reliability Assessment of Potter and Brumfield MDR Series Relays."
11. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.
12. WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems, Diablo Canyon Units 1 and 2, 24 Month Fuel Cycle and Replacement Steam Generator Evaluation," September 2007.
13. Calculation J-54, "Nominal Setpoint Calculation for Selected PLS Setpoints."
14. J-110, "24 Month Fuel Cycle Allowable Value Determination / Documentation and ITDP Uncertainty Sensitivity."
15. License Amendment 61/60, May 23, 1991.
16. WCAP-14036-P-A, Revision 1, “Elimination of Periodic Protection Channel Response Time Tests,” October 1998.
17. WCAP-14333-P-A, Revision 1, “Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,” October 1998.
18. WCAP-15376-P-A, Revision 1, “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” March 2003.
19. 10 CFR 50.55a(h), "Protection and Safety Systems."
20. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.
21. Attachment 1 to TSTF-569, “Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing,” August 2019.

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 in UFSAR Section 7.5 (Ref. 1) based upon 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/or 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.

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

(continued)

BASES

BACKGROUND (continued)	• Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat. 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 preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA); • Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function; • Determine whether systems important to safety are performing their intended functions; • Determine the likelihood of a gross breach of the barriers to radioactivity release; • Determine if a gross breach of a barrier has occurred; and • Initiate action necessary to protect the public and to estimate the magnitude of any impending threat. PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii). Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk.
LCO	The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

(continued)

BASES

LCO (continued)

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

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

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, Auxiliary Feedwater (AFW) flow indication and Steam Generator (SG) water level (wide range). For the CIV position, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. 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. 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.

There are 4 total required SG water level (wide range) and 4 total required AFW flow indication channels, with one indicator for each SG. The redundancy for these two Functions is provided by the presence of 4 Steam Generators. Therefore, for these two instrument Functions, Condition A is applicable for the loss of a single indicator.

There is one wide range water level indicator for each steam generator in the main control room. Wide range steam generator level measurement meets the intent of the single failure criterion for Category 1 variables by virtue of independent, diverse variables. Auxiliary feedwater (AFW) flow, narrow range SG level, SG pressure, reactor coolant pressure, and reactor coolant temperature indications are diverse variables which can be used to assist in determining whether adequate core cooling is provided. The wide range SG level is used to assist in determining the loss of the heat sink. Having one wide range level indicator, in conjunction with one AFW flow indicator, per SG is consistent with NUREG-0737 Item II.E.1.2 for Westinghouse plants.

(continued)

BASES

LCO
(continued)

There is one AFW flow rate indicator for each SG in the main control room. Diverse indications are available from one wide range level indicator and three narrow range level indicators per SG. The four AFW flow rate indicators are powered by two separate critical instrument power buses, with two AFW flow rate indicators on each bus. Since only two of four SGs are required to establish a heat sink for the RCS, flow indication to at least two intact SGs is assured even if a single failure is assumed.

Table 3.3.3-1 includes instrumentation which is classified as either Type A and/or Category I variables in accordance with Regulatory Guide 1.97, UFSAR Section 7.5, and SER 14.

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (Ref. 2) design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display, except as exempted in SSER 31. Regulatory Guide 1.97, for certain Functions, requires that the Function be recorded on at least one channel. For these channels where direct and immediate trend or transient information is not essential for operator information, or both channels would be recorded per Regulatory Guide 1.97, the loss of the recorder is not considered to be a loss of Function. However, the recorder should be returned to service as soon as possible and an alternate means of obtaining the recorded information be established if the recorder is to be out-of service beyond the channel AOT.

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

1. Neutron Flux (Wide Range NIS)

   Neutron Flux indication is provided to verify reactor shutdown. The wide range NIS is 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.

2. Steam Line Pressure

   Steam pressure is used to determine if a high energy secondary line rupture has occurred and the availability of the steam generators as a heat sink. It is also used to verify that a faulted steam generator is isolated. Steam pressure may be used to ensure proper cooldown rates or to provide a diverse indication for natural circulation cooldown.

(continued)

BASES

LCO (continued)

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

RCS Hot and Cold Leg Temperatures are Category I variables provided for verification of core cooling and long term surveillance. The intent of requiring this instrumentation is to be able to monitor ΔT. Therefore, to have an OPERABLE RCS inlet and outlet temperature, they should be in the same primary loop. If the outlet temperature is inoperable, core exit thermocouples can be used in conjunction with RCS inlet temperature to determine ΔT.

RCS hot (outlet) and cold (inlet) leg temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow termination of safety injection (SI), if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control. RCS hot leg temperature also provides a temperature compensating signal for the reactor vessel level instrumentation system (RVLIS).

In addition, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify the unit conditions necessary to establish natural circulation in the RCS. The RCS cold leg temperature also provides a temperature input signal for the low temperature overpressure protection (LTOP) system.

Reactor outlet temperature inputs to the Reactor Protection System are provided by two fast response resistance elements and associated transmitters in each loop. The channels provide indication over a range of 0°F to 700°F.

Each of the 4 hot legs and each of the 4 cold legs has one wide range RTD. These are separate from the narrow range RTDs providing input into the Reactor Protection System.

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 delivery of SI flow to RCS from at least one train when the RCS pressure is below the pump shutoff head. RCS pressure is also used to verify closure of manually closed spray line valves and pressurizer power operated relief valves (PORVs).

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

(continued)

BASES

LCO

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

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

Two final uses of RCS pressure are to determine whether to operate the pressurizer heaters and as an input to Reactor Vessel Water Level Instrumentation System (RVLIS).

RCS pressure is a Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

6. Reactor Vessel Water Level Indication System (RVLIS)

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

The RVLIS provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

(continued)

BASES

LCO (continued)

7. <u>a. Containment Recirculation Sump Level (Narrow Range) and</u>

<u>b. Containment Reactor Cavity Sump Water Level (Wide Range)</u>

Containment Recirculation Sump Level (Narrow Range) is used to verify that sufficient water is contained in the recirculation sump to allow operation of the Residual Heat Removal Pumps with the suction aligned to the containment recirculation sump.

Containment Reactor Cavity Sump Water Level (Wide Range) is provided for verification and long term surveillance of RCS integrity. The required Regulatory Guide 1.97 recorder for this function is part of this instrument channel.

The Containment Reactor Cavity Sump level instrumentation encompasses the range of the Containment Recirculation Sump and can be used to determine the appropriate time for swap-over of the RHR pumps from RWST to the Containment Recirculation Sump if required.

8. <u>a. Containment Pressure (Wide Range) and</u>

b. <u>Containment Pressure (Normal Range)</u>

Containment Pressure is provided for verification of RCS and containment OPERABILITY.

Containment pressure is used to verify closure of main steam isolation valves (MSIVs) during a main steam line break inside containment, and containment spray Phase B isolation when high-high containment pressure is reached.

Both instruments are required to cover the Regulatory Guide 1.97 range requirements.

9. <u>Containment Isolation Valve Position</u>

CIV Position is provided for verification of Containment OPERABILITY, and Phase A and Phase B isolation, and containment ventilation system 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

(continued)

BASES

LCO

9. Containment Isolation Valve Position (continued)

of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. 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. This Function is on a per valve basis and ACTION A is entered separately for each inoperable valve indication. 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.

10. Containment Area Radiation (High Range)

Containment Area Radiation is provided to monitor for the potential of significant radiation releases for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine if a high energy line break (HELB) containing radioactive fluid has occurred, and whether the event is inside or outside of containment.

11. Not used

12. 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.

(continued)

BASES

LCO (continued)

13. a. Steam Generator Water Level (Wide Range) and

b. Steam Generator Level (Narrow Range)

SG Water Level (Wide Range) is provided to monitor operation of decay heat removal via the SGs. The wide range level covers a span of approximately 10 inches above the tubesheet to the steam generator separator. The measured differential pressure is displayed in percent level (cold calibration).

SG Water Level is used to:

- identify the faulted 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 an SGTR); and
- verify unit conditions for termination of SI during secondary unit HELBs outside containment.

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, the reflux cooling mode of heat transfer is necessary to remove decay heat. Wide range level is a Type A variable because the operator must manually raise and control SG level to establish reflux cooling heat transfer. Operator action is initiated on a loss of subcooled margin. Feedwater flow is increased until the indicated wide range level reaches the reflux cooling initiation point.

There are 4 total required Steam Generator Wide Range Channels with one required on each steam generator. The redundancy of this Function is provided by the presence of 4 Steam Generators.

SG Water Level (Narrow Range) is redundant to the SG wide range level, and provides indication of adequate RCS heat removal capability during normal SG inventory conditions. The narrow range level covers a span from ≥ approximately 373 inches to approximately 585 inches above the tubesheet.

There are 3 Steam Generator Narrow Range Channels per steam generator with 2 required for this function.

14. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System. CST Level is displayed on a control room indicator, strip chart recorder, and unit computer.

(continued)

BASES

LCO

14. Condensate Storage Tank (CST) Level (continued)

CST Level is considered a Type A variable because the control room meter is the primary indication used by the operator.

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

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps from the Fire Water Storage Tank or other alternate sources.

15, 16, 17, 18. In-Core Thermocouples

In-Core Thermocouples are provided for verification and long term surveillance of core cooling.

An evaluation was made of the minimum number of valid in-core thermocouples necessary for measuring core cooling. The evaluation determined the reduced complement of in-core thermocouple necessary to detect initial core recovery and trend the ensuing core heatup. The evaluations account for core nonuniformities, including incore effects of the radial decay power distribution, excore effects of condensate runback in the hot legs, and nonuniform inlet temperatures. Based on these evaluations, core cooling can be adequately monitored with two valid in-core thermocouple channels per quadrant with two in-core thermocouples per required channel. Core Exit Temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core Exit Temperature is also used for unit stabilization and cooldown control.

Two OPERABLE channels of In-Core Thermocouples are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. Therefore, two randomly selected thermocouples are not sufficient to meet the two thermocouples per channel requirement in any quadrant. The two thermocouples in each channel must meet the additional requirement that one is located near the center of the core and the other near the core perimeter, such that the pair of Core Exit Temperatures indicate the radial temperature gradient across their core quadrant. Unit specific evaluations in response to Item II.F.2 of NUREG-0737 (Ref. 3) should have identified the thermocouple pairings that satisfy these requirements. Two sets of two thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient.

(continued)

BASES

LCO
(continued)

The incore thermocouple system consists of 2 redundant trains. The highest thermocouple reading from each train is an input to its respective train of sub-cooled margin monitor (SCMM) which is used for determination of RCS subcooling margin during normal and accident plant conditions. During plant accident condition, RCS subcooling margin is used to allow termination of safety injection, if still in progress, or reinitiation of safety injection if it has been stopped. It is also used for unit stabilization and cooldown control.

19. Auxiliary Feedwater (AFW) Flow

AFW Flow is provided to monitor operation of decay heat removal via the SGs. One AFW flow channel is provided for each steam generator.

The AFW Flow to each SG is determined from a differential pressure measurement calibrated for a range of 0 gpm to 300 gpm. Each differential pressure transmitter provides an input to a control room indicator and the unit computer. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

AFW flow is used three ways:

- to verify delivery of AFW flow to the SGs;
- to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and
- to regulate AFW flow so that the SG tubes remain covered.

AFW flow is a Type A variable because operator action is required to throttle flow during an SLB accident to prevent the AFW pumps from operating in runout conditions. AFW flow is also used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level (Narrow Range) during normal SG inventory conditions.

There are 4 total required AFW flow Channels with one indicator for each Steam Generator. The redundancy of this Function is provided by the presence of 4 Steam Generators.

20. Refueling Water Storage Tank (RWST) Water Level

RWST water level is used to verify the water source availability to the emergency core cooling system (ECCS) and Containment Spray Systems. It may also provide an indication of time for initiating cold leg recirculation from the sump following a LOCA. The RWST level channel additionally trips the Residual Heat Removal Pumps in preparation for transfer to cold leg recirculation.

(continued)

BASES (continued)

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. When the required channels in Table 3.3.3-1 are specified on a per steam generator basis, then the Condition may be entered separately for each steam generator.

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

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies when one or more Functions have two or more inoperable required channels (i.e., two or more channels inoperable in the same function). Required Action C.1 requires restoring all but 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 no required channels OPERABLE 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 all but 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

Condition D applies when the Required Action and associated Completion Time of Condition C is not met. Required Action D.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action of Condition C, and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C is not met and Table 3.3.3-1 directs entry into Condition E, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

(continued)

BASES

ACTIONS

E.1 and E.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.

F.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. Monitoring the Core Exit Thermocouples, Pressurizer Level indication (07-LI-459A, 460A or 461), and RCS Subcooling Monitor indication (07-YI-31) provide an alternate means for RVLIS. These three parameters provide diverse information to verify there is adequate core cooling or RCS inventory. When Containment Area Radiation Level (High Range) monitors (R-30 and R-31) are inoperable, selected portable radiation monitoring equipment is made available for taking correlated readings at the equipment or personnel hatches as the alternate method. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

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

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. CHANNEL CALIBRATION of the Neutron Flux Wide Range Function excludes the detectors. To ensure that the detectors are verified, the Neutron Flux Wide Range Channels are cross-correlated and normalized to reactor thermal power. CHANNEL CALIBRATION of the Containment Radiation Level (High Range) Function may consist of an electronic calibration of the channel, not including the detector, for range decades above 10R/h and a one point calibration check of the detector below 10 R/h with an installed or portable gamma source. Whenever an RTD is replaced in Functions 3 or 4, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. Whenever an incore thermocouple is replaced in Function 15, 16, 17, or 18 the next required CHANNEL CALIBRATION of the incore thermocouples is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. For function 9, Containment Isolation Valve Position, the instrument loop consists of the position switch mounted on the valve, the indication lights in the monitor boxes and the interconnecting wiring. For the CHANNEL CALIBRATION to verify that the channel

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.3.3.2 (continued) responds with the necessary range and accuracy, the test must verify that the proper indication is received when the valve is stroked to the fully closed position. Verification of intermediate position or actual percentage closed is not required, however, for OPERABILITY, the position indication must be able to communicate the proper isolation status of the containment penetration. Adjustments to the channel may be done as part of this surveillance or through other controlled instructions. 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 7.5. 2. Regulatory Guide 1.97, Revision 3. 3. NUREG-0737, Supplement 1, "TMI Action Items." 4. Supplemental Safety Evaluation Report 14. 5. Supplemental Safety Evaluation Report 31.

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 place and 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) safety valves can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System allows extended operation in MODE 3 until such time that either control is transferred back to the Control Room or a cooldown is initiated from outside the control room.

If the control room becomes inaccessible, the operators can establish control at the remote shutdown panel (hot shutdown panel), and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the hot 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 following remote shutdown control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible.

(continued)

BASES (continued)

INSTRUMENT/CONTROL FUNCTION		READOUT/CONTROL LOCATION	REQUIRED CHANNELS
1.	Reactor Trip Breaker Indication	Reactor Trip Breaker	1/trip breaker
2.	Pressurizer Pressure	Hot Shutdown Panel (PI-455B)**	1
3. & 4.	RCS Loop 1 Temperature Indication	Dedicated Shutdown Panel	Hot and Cold Leg Temperature Indication
5.	Auxiliary Feedwater Flow Control		2 of 3 AFW pumps
	— AFW Pump, and Associated Valves	Hot Shutdown Panel	
	— Transfer Switches	4.16-kV Switchgear	
6.	Steam Generator Pressure	Hot Shutdown Panel (PI-514B, 524B, 534B, 544B)**	1/stm. gen.
7.	Steam Generator Wide Range Water Level	Hot Shutdown Panel (LI-501, 502, 503, 504)**	1/stm. gen.
8.	Auxiliary Feedwater Flow	Hot Shutdown Panel (FI-165, 166, 167, 168)**	1/stm. gen.
9.	Condensate Storage Tank Water Level	Hot Shutdown Panel	1
10.	Pressurizer Level	Hot Shutdown Panel (LI-459B, 460B)**	1
11.	Charging Flow Control		2 of 2 pumps
	— Centrifugal Charging Pump	Hot Shutdown Panel	
	— Transfer Switch	4.16-kV Switchgear	
12.	Charging Flow	Hot Shutdown Panel	1
13.	Emergency Diesel Generator Control		3 of 3 EDGs
	— EDG Start	EDG Local Control Panel	
	— EDG Breaker Control/Transfer Switch*	4.16-kV Switchgear	

(continued)

BASES (continued)

INSTRUMENT/CONTROL FUNCTION	READOUT/CONTROL LOCATION	REQUIRED CHANNELS
14. Component Cooling Water Control		2 of 3 CCW pumps
— Component Cooling Water Pump	Hot Shutdown Panel	
— Transfer Switch	4.16-kV Switchgear	
15. Auxiliary Salt Water Control		2 of 2 pumps
— Auxiliary Saltwater Pump	Hot Shutdown Panel	
— Transfer Switch	4.16-kV Switchgear	

* Added per Reference 2.

**NFPA 805 project added backup and alternate instruments to the hot shutdown panel for these parameters; however, the new instruments are not credited in the Technical Specifications (References 3 and 4). Therefore, instrument IDs for instruments that are credited in the Technical Specifications are listed for these parameters to distinguish between credited and non-credited instrumentation.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and 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 10 CFR 50, Appendix A, GDC 19, 1971 (Ref. 1). The Remote Shutdown System is considered an important contributor to the reduction of unit risk to accidents and as such it has been retained in the Technical Specifications as indicated by Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The Remote Shutdown System LCO provides the OPERABILITY requirements of the functions necessary to place and maintain the unit in MODE 3 from a location other than the control room. The functions required are listed in Table 3.3.4-1 in the accompanying LCO. The controls, instrumentation, and transfer switches are required for the individual functions that provide the following general functions: • Reactor trip indication; • RCS pressure control; • Decay heat removal via the AFW System and the SG safety valves; • RCS inventory control via charging flow; and • Safety support systems for the above Functions, including auxiliary saltwater, component cooling water, and diesel generators. A Function of a Remote Shutdown System is OPERABLE if all required instrument and control channels for that function listed in Table 3.3.4-1 are 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.

(continued)

BASES (continued)

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room until either control is transferred back to the control room or a cooldown is initiated.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1. 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 any Function listed in Table 3.3.4-1, as well as the control and transfer switches.

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.

(continued)

BASES (continued)

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 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 the channels are normally off scale during times when Surveillance is required, the CHANNEL CHECK will verify only that they are off scale in the same direction. Offscale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

The CHANNEL CHECK for the RTB serves to verify that the indication correctly indicates the position of the RTB.

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 hot 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 placed and 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.3.4.2 (continued) The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. SR 3.3.4.3 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. The channel calibration is not applicable to the RTB indication. Whenever an RTD is replaced in Function 3.a or 3.b, the next required CHANNEL CALIBRATION of the RTDs 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. 10 CFR 50, Appendix A, GDC 19, 1971 (associated with 1967 GDC 11 per UFSAR Appendix 3.1A.). 2. SAPN 50610685 Tech Spec Bases B3.3.4 3. DCP Number: 1000025004 – Unit 2 – NFPA 805 Hot Shutdown Panel Modification 4. DCP Number: 1000024930 – Unit 1 – NFPA 805 Hot Shutdown Panel Modification

B 3.3 INSTRUMENTATION

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

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is degraded below a point that would allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs on the 4.16-kV Class 1E bus. There are three LOP start signals, one for each 4.16-kV Class 1E bus.

Three undervoltage relays are provided on each 4.16-kV Class 1E bus for detecting sustained degraded voltage condition or a loss of bus voltage. A relay will generate an LOP signal (first level undervoltage type relay setpoint) if the voltage is below 75% for a short time. The DG start relays (one per bus) have an inverse time characteristic and will generate an LOP signal with a ≤ 0.8 sec time delay at ≥ 0 volts and at ≤ 10 seconds for ≥ 2583 volts. In addition, the circuit breakers for all loads, except the 4.16-kV to 480-V load center transformers, are opened automatically by Load Shedding Relays for first level undervoltage. Each of the Class 1E 4.16-kV buses has a separate pair of these relays. The relays have a two-out-of-two logic arrangement for each bus to prevent inadvertent tripping of operating loads during a loss of voltage either from a single failure in the potential circuits or from human error. One relay trips instantaneously at ≥ 2870 volts. The second of the two relays has an inverse time characteristic and delay of ≤ 4 seconds at no voltage and a ≤ 25 second delay with ≥ 2583 volts to prevent loss of operating loads during transient voltage dips, and to permit the offsite power sources to pick up the load. The LOP start actuation is described in UFSAR, Section 8.3 (Ref. 1).

Should there be a degraded voltage condition (second level undervoltage), where the voltage of the Class 1E 4.16-kV buses remains at approximately 3785-V or below, but above the setpoints of the first level undervoltage relays, the following second level undervoltage actions occur automatically:

(1) After a ≤ 10 second time delay, the respective diesel generators will start.

(2) After a ≤ 20 second time delay, if the undervoltage condition persists, the circuit breakers for all loads to the respective Class 1E 4.16-kV buses, except the 4.16-kV to 480-V load center transformer, are opened and sequentially loaded on the DG.

(continued)

BASES

BACKGROUND (continued)	Each Class 1E 4.16-kV bus has two second level undervoltage relays operating with a two-out-of-two logic. Each Class 1E 4.16-kV Bus also has two second level undervoltage timers. One timer provides the Diesel Generator start and the other will initiate load shedding. <u>Allowable Value Setpoints</u> The Setpoints used in the relays are based on the analytical limits presented in UFSAR, Chapter 15 (Ref. 2). The selection of these Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. The actual nominal Setpoint entered into the relays is normally still more conservative than that required by the Allowable Value. If the measured setpoint does not exceed the Allowable Value, the undervoltage relay is considered OPERABLE. If the measured time delay does not exceed the Allowable Value, the timer is considered OPERABLE. Setpoints adjusted in accordance with 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 the LCO. The nominal setpoints are selected to ensure that the setpoint measured by the surveillance procedure does not exceed the Allowable Value if the undervoltage relay is performing as required. If the measured setpoint does not exceed the Allowable Value, the undervoltage relay is considered OPERABLE. Operation with a Setpoint less conservative than the nominal Setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint calculation. Each Allowable Value specified is more conservative than the analytical limit assumed in the transient and accident analyses in order to account for instrument uncertainties appropriate to the trip function. These uncertainties are defined in calculation 357R-DC (Ref. 4).
APPLICABLE SAFETY ANALYSES	The LOP DG 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 ESF Actuation System (ESFAS).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions. The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed. The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay. The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO for LOP DG start instrumentation requires that one channel per bus for loss of voltage DG start with, two channels per bus for initiation of load shed and their two corresponding timers and two channels per bus of degraded voltage function with one timer per bus for DG start and one timer per bus for initiation of load shed Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, the channels must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. Loss of the LOP DG 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 DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

(continued)

BASES (continued)

APPLICABILITY	The LOP DG 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 DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the Class 1E bus.
ACTIONS	In the event a channel's 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. 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. <u>A.1</u> Condition A applies when one or more of the loss of voltage or the degraded voltage channel functions (this includes both relays and timers) on a single bus are inoperable. In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources-Operating," or LCO 3.8.2, "AC Sources-Shutdown," for the DG made inoperable by failure of the LOP instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety. A Note is added to allow bypassing one channel for up to 2 hours for surveillance testing. This allowance is made where bypassing the channel does not cause an actuation and where at least one other channel is monitoring that parameter.
SURVEILLANCE REQUIREMENTS	<u>SR 3.3.5.1</u> not used <u>SR 3.3.5.2</u> SR 3.3.5.2 is the performance of a TADOT. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. For these tests, the relay Setpoints are verified and adjusted as necessary. 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 (continued)	SR 3.3.5.3 SR 3.3.5.3 is the performance of a CHANNEL CALIBRATION. The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 8.3. 2. UFSAR, Chapter 15. 3. Blank 4. Calculation 357R-DC, "4.16-kV Bus Under-Voltage Relay & Timer"

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Ventilation Isolation Instrumentation

BASES

BACKGROUND	Containment ventilation isolation instrumentation closes the containment purge supply (FCV-660, 661), exhaust (RCV-11, 12), and the vacuum/pressure relief valves (FCV-662, 663, 664). It also closes the containment atmosphere sample valves (FCV-678, 679, 681). This action in conjunction with a Phase A signal isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Purge or Vacuum/Pressure Relief System may be in use during reactor operation or reactor shutdown. Containment ventilation isolation initiates on a automatic safety injection (SI) signal through the Containment Isolation-Phase A Function, or by manual actuation of Phase A Isolation. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation, "discuss these modes of initiation. Two radiation monitoring channels (RM 44A and 44B) are also provided as input to the containment ventilation isolation. The two channels measure containment radiation in the exhaust duct for fan E-3. Both detectors will respond to events that release radiation to containment. Both monitors are gaseous activity monitors that will respond to noble gases, particulate and Iodine. The high alarm setpoint is based upon the design basis fuel handling accident source term which does not have a particulate component. The actual high alarm setpoint is more than a factor of 500 below the design calculation earliest actuation point. Since the monitors can only be adjusted to one high alarm setpoint and no particulate is expected during a fuel handling accident, a setpoint based on site boundary noble gases is conservative. For the purposes of this LCO the channels are redundant. A high radiation signal from either of the two channels initiates containment ventilation isolation, which closes the containment ventilation isolation valves. These systems are described in the Bases for LCO 3.6.3, "Containment Isolation Valves."
APPLICABLE SAFETY ANALYSES	The safety analyses assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event, within approximately 60 seconds. The isolation of the containment ventilation valves has not been analyzed mechanistically in the dose calculations, although its isolation, using a conservative isolation time, is assumed. The containment ventilation isolation radiation monitors act as backup to the SI signal to ensure closing of the containment ventilation isolation valves following a LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	They are also the primary means for automatically isolating containment in the event of a fuel handling accident or any other source within containment during shutdown. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental offsite radiological doses are below 10 CFR 50.67 (Ref. 1) limits. Due to radioactive decay, containment is only required to isolate 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.) The containment ventilation isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO requirements ensure that the instrumentation necessary to initiate Containment Ventilation Isolation, listed in Table 3.3.6-1, is OPERABLE. 1. <u>Manual Initiation</u> - Not used 2. <u>Automatic Actuation Logic and Actuation Relays</u> The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation. Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b, SI, and ESFAS Function 3.a, Containment Phase A Isolation. The applicable MODES and specified conditions for the Containment Ventilation Isolation portion of these Functions are different and less restrictive than those for their Phase A isolation and SI roles. If one or more of the SI or Phase A isolation Functions becomes inoperable in such a manner that only the Containment Ventilation Isolation Function is affected, the Conditions applicable to their SI and Phase A isolation Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Ventilation Isolation Functions specify sufficient compensatory measures for this case. 3. <u>Containment Radiation</u> The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment ventilation Isolation remains OPERABLE in MODES 1-4. The LCO only requires one monitor to be OPERABLE during movement of recently irradiated fuel assemblies in containment. In order to provide the CVI function under these conditions without placing the entire SSPS in service, an alternate circuit is provided to power the output relays and provide logic actuation signals independent of the SSPS.

(continued)

BASES

LCO

3. Containment Radiation (continued)

This circuit also disconnects the normal logic and actuation paths such that only high radiation signals may generate a CVI.

4. Containment Isolation - SI

Refer to LCO 3.3.2, Function 1 and 3, for all initiating Functions and requirements.

APPLICABILITY

The Automatic Actuation Logic and Actuation Relays, Containment Isolation-Phase A, and Containment Radiation Functions are required OPERABLE in MODES 1, 2, 3, and 4, and during movement of recently irradiated fuel assemblies within containment. Under these conditions, the potential exists for an accident that could release significant fission product radioactivity into containment. Therefore, the containment ventilation isolation instrumentation must be OPERABLE in these MODES.

While in MODES 5 and 6 without fuel handling in progress, the containment ventilation isolation instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a CFT and/or CHANNEL CALIBRATION, when the process instrumentation is set up for adjustment to bring it within specification. Drift can also be observed during a CHANNEL CHECK or CFT and if observed would prompt action to correct the discrepancy. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the failure of one Containment ventilation Isolation radiation monitor channel. The 4 hours allowed to restore the affected channel is justified by the low likelihood

(condition)

BASES

ACTIONS

A.1 (continued)

of events occurring during this interval, and recognition that the remaining channel will respond.

A Note has been added to state that Condition A is only applicable in MODE 1, 2, 3, or 4.

B.1

Condition B applies to all Containment Ventilation Isolation Functions and addresses the train orientation of the Solid State Protection System (SSPS) and the master and slave relays for these Functions. It also addresses the failure of both radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, both radiation channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 to place and maintain containment ventilation isolation valves (RCV-11, 12, FCV-660, 661, 662, 663, 664) in their closed position is met. The completion Time for these Required Actions is Immediately.

Although FCV-678, 679, and 681 are also categorized as containment ventilation isolation valves, they are not required to be closed due to this Condition. The reason is that it is undesirable to have these valves closed during normal and refueling activities because this results in the loss of operability of containment radioactivity monitors RM-11 and RM-12 which play an important part in RCS leak detection in Modes 1, 2, 3, and 4 (Ref. 3).

A Note is added stating that Condition B is only applicable in MODE 1, 2, 3, or 4.

C.1 and C.2

Condition C applies to all Containment Ventilation Isolation Functions and addresses the train orientation of the SSPS and the master and slave relays for these Functions. It also addresses the condition of no OPERABLE radiation monitoring channels. If a train is inoperable, or the required radiation monitor is inoperable, operation may continue as long as the Required Action to place and maintain containment ventilation isolation valves (RCV-11, 12, FCV 660, 661, 662, 663, 664) in their closed position is met or the applicable Conditions of LCO 3.9.4, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. The Completion Time for these Required Actions is Immediately.

(continued)

BASES (continued)

ACTIONS (continued)	A Note states that Condition C is applicable during movement of recently irradiated fuel assemblies within containment.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Ventilation Isolation Functions.

SR 3.3.6.1

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

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

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

SR 3.3.6.2

SR 3.3.6.2 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. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. 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 (continued)

SR 3.3.6.3

SR 3.3.6.3 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 3.3.6.4

A CFT is performed on each required channel to ensure the entire channel will perform the intended Function. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. This test verifies the capability of the instrumentation to provide the containment purge and vacuum/pressure relief system isolation.

To ensure complete end-to-end testing through the CVI mode selector switch, the CFT is only valid for the position in use during the test.

SR 3.3.6.5

SR 3.3.6.5 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.

SR 3.3.6.6

There is no manual actuation of CVI except via SI, phase A or B. This testing is performed as part of SR 3.3.2.8

SR 3.3.6.7

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.7 (continued)

The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.8

This SR assures that the individual channel RESPONSE TIMES for the CVI from Containment Purge Radiation Gaseous and Particulate function are less than or equal to the maximum values assumed in the accident analysis. Response Time testing acceptance criteria are included in ECG 38.2. Individual component response times are not modeled in the analyses. The analyses model the overall or 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., valves in full closed position). The response time may be measured by a series of overlapping tests such that the entire response time is measured.

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 50.67.
2. NUREG-1366, December 1992.
3. DCM No. T-16, Containment Function.
4. WCAP-15376-P-A, Revision 1, “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” March 2003.
5. License Amendment 184/186, January 3, 2006.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

BASES

BACKGROUND

The CRVS provides an enclosed control room environment from which both units can be operated following an uncontrolled release of radioactivity. Upon receipt of an actuation signal, the CRVS shifts from normal operation and initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.10, "Control Room Ventilation System", and is common to both units.

The CRVS Actuation Instrumentation system is also common to both units and consists of two trains of Automatic Actuation Relays (one train in each unit) and two channels of Control Room (CR) Radiation Atmosphere Air Intakes (two intake systems). One channel of CR Radiation Atmosphere Air Intakes consists of at least one of two redundant radiation monitors in a respective air intake to the control room areas. These channels therefore, have two detectors in each of the two normal control room air intakes. However, since they take suction from a common area, the North and South sides of the mechanical equipment room, only one detector per unit is required in each air intake to provide protection against a single failure, therefore, the total required detectors is two for the common control room area (one in each intake). One train of Automatic Actuation Relays consists of two sets of actuation relay logic. Each set receives an input from its respective radiation monitor and a Phase A / SI signal from a train of SSPS. Only one relay logic set in each unit is necessary to satisfy a TS train requirement. A Phase "A" containment isolation signal or a high radiation signal from either of the required detectors in the normal intake will initiate CRVS pressurization from the opposite unit pressurization system (the system selects the opposite unit assuming that pressurization would be the lowest radiation level), or from the pressurization intake with the lowest radiation level (each pressurization intake, one on the North end of the turbine building and one on the South, has two additional radiation monitors. This provides the ability to swap the pressurization intakes. This is an added feature of the system, but is not credited in any accident scenarios, thus it is not required for CRVS OPERABILITY). Only the actuation of the pressurization system via an SI signal directly is processed through the SSPS. The actuation of the pressurization system via an atmosphere intake monitor directly actuates the CRVS actuation relays independent of the SSPS. The control room operator can also initiate CRVS pressurization by manual switches in the control room.

(continued)

BASES

BACKGROUND (continued)	The CRVS has two additional manually selected emergency operating modes; smoke removal and recirculation. Neither of these modes are required for the CRVS to be OPERABLE, but they are useful for certain non-DBA circumstances.
APPLICABLE SAFETY ANALYSES	The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations. The CRVS acts to terminate the supply of unfiltered outside air to the control room, initiate filtration, and pressurize the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel. In MODES 1, 2, 3, and 4, the radiation monitor (located at the control room intakes) actuation of the CRVS is a backup for the Phase A signal actuation. This ensures initiation of the CRVS during a loss of coolant accident, steam generator tube rupture, control rod ejection accident and Main Steam Line Break. The radiation monitor actuation of the CRVS in MODES 5 and 6, during movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours), is the primary means to ensure control room habitability in the event of a fuel handling or waste gas decay tank rupture accident. This actuation is credited in the FHA. The CRVS pressurization system actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). In MODES 1, 2, 3, 4, 5 and 6 credit is taken for the dual ventilation intake design of the CR pressurization air intakes. Based on the availability of redundant PG&E Design Class I radiation monitors at each pressurization intake location, the DCPP design has the capability of initial selection of the cleaner intake, but does not have the capability of automatic selection of the clean intake throughout the event. Based on the CRVS pressurization intake design, and the expectation that the operator will manually make the proper intake selection throughout the event, and per RG 1.194, June 2003, Regulatory Position C.3.3.2.3, when the CRVS is in filtered/pressurized emergency ventilation mode, the X/Q values for the more favorable CR intake is reduced by a factor of 4 and utilized to estimate the dose consequences.

(continued)

BASES (continued)

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CRVS pressurization system is OPERABLE.

1. Manual Initiation

   The LCO requires two trains OPERABLE. The operator can initiate the CRVS pressurization mode 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 Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

2. Automatic Actuation Relays

   The LCO requires two trains of Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation of the pressurization system. Since each unit has one train of Actuation Relays consisting of two sets of actuation logic, each unit must have at least one logic set for both trains to be considered OPERABLE.

(continued)

BASES

LCO	2. Automatic Actuation Relays (continued) If one or more of the SI or Phase A functions becomes inoperable in such a manner that only the CRVS function is affected (such as a Phase A Slave Relay output to the CRVS logic), the Conditions applicable to their SI or Phase A functions need not be entered. The less restrictive Actions specified for inoperability of the CRVS Functions specify sufficient compensatory measures for this case. 3. Control Room Radiation Atmosphere Air Intakes The LCO specifies two required channels of Control Room Normal Intake Radiation Monitors to ensure that the radiation monitoring instrumentation necessary to initiate the CRVS pressurization system remains OPERABLE. One channel consists of two Radiation Monitors per intake, however, only one monitor is necessary for the channel to be OPERABLE. 4. Safety Injection Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements. As noted above, a safety injection signal does not directly initiate CRVS pressurization, but a Phase A signal does and Phase A is initiated by SI.
APPLICABILITY	The CRVS Functions must be OPERABLE in MODES 1, 2, 3, 4, and during movement of recently irradiated fuel assemblies. The Functions must also be OPERABLE in MODES 5 and 6 when required for a waste gas decay tank rupture accident, or a fuel handling or core alteration accident to ensure a habitable environment for the control room operators.
ACTIONS	The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by the unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a CFT and/or CHANNEL CALIBRATION, when the process instrumentation is set up for adjustment to bring it within specification. Drift can also be observed during a CHANNEL CHECK or CFT and if observed would prompt action to correct the discrepancy. If the Trip Setpoint is less conservative than the acceptance criteria specified by the calibration procedure, the instrument must be declared inoperable immediately and the appropriate Condition entered.

(continued)

BASES

ACTIONS (continued)

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the actuation train Function of the CRVS, the intake radiation monitor channel Functions, and the manual channel Functions.

If one complete actuation train is inoperable, or one complete intake radiation monitor channel is inoperable in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10. If the complete channel/train cannot be restored to OPERABLE status, one CRVS train must be placed in the pressurization mode of operation. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

B.1.1 and B.1.2

Condition B applies to the failure of two complete CRVS actuation trains, two complete intake radiation monitor channels, or two manual channels. The first Required Action is to place one CRVS train in the pressurization mode of operation immediately. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. Both trains cannot be placed in the pressurization mode since the design of the system is such that operation of two pressurization fans would overpressurize the supply ducting to the filters. The applicable Conditions and Required Actions of LCO 3.7.10 must also be entered for the CRVS train made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.10.

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 overall plant risk is reduced. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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. Movement of recently irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require CRVS actuation.

E.1

Condition E applies when the Required Action and associated Completion Time for Condition A or B have not been met in MODE 5 or 6. Actions must be initiated to restore the inoperable train(s) to OPERABLE status immediately to ensure adequate isolation capability in the event of a waste gas decay tank rupture.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

E.1 (continued)

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CRVS Actuation Functions.

SR 3.3.7.1

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

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

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 (continued)

SR 3.3.7.2

A CFT is performed once on each required radiation monitor to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CRVS actuation. The CRVS pressurization system actuation relays are directly actuated by the CRVS atmosphere intake radiation monitors. This signal is not processed through the SSPS, but goes directly to the CRVS actuation relays. The pressurization system is also actuated by Phase A, however, this signal is processed via the SSPS and the testing of the associated relays is performed via SR 3.3.2.2, SR 3.3.2.4, and SR 3.3.2.6. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.3

SR 3.3.7.3 is the performance of an ACTUATION LOGIC TEST. This test verifies the signal path to the Master Relay Coil. Although there are no "Master Relays" as in the SSPS, this surveillance was maintained to preserve the format of the standard specification. The surveillance is intended to ensure that the complete logic is tested for the function. Since the radiation monitors directly actuate the actuation relays, this test is performed as part of the performance of SR 3.3.7.2.

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

SR 3.3.7.4

SR 3.3.7.4 is the performance of a MASTER RELAY TEST. This test energizes the Master Relay and verifies the actuation signal injected into the Slave Relays. Although there are no "Master Relays" as in the SSPS, this surveillance was maintained to preserve the format of the standard specification. The surveillance is intended to ensure that the complete logic is tested for the function. Since the radiation monitors directly actuate the actuation relays, this test is performed as part of the performance of SR 3.3.7.2.

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 (continued)

SR 3.3.7.5

SR 3.3.7.5 is the performance of a SLAVE RELAY TEST. This test energizes the Slave Relays and verifies actuation of the equipment to the pressurization mode. Although there are no "Slave Relays" as in the SSPS, this surveillance was maintained to preserve the format of the standard specification. The surveillance is intended to ensure that the actuation relays, downstream of the logic, function to actuate the pressurization mode equipment. Since the radiation monitors directly actuate the actuation relays, this test is performed as part of the performance of SR 3.3.7.2.

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

SR 3.3.7.6

SR 3.3.7.6 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. 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.

SR 3.3.7.7

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

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

(continued)

BASES
(continued)

REFERENCES

1. WCAP-13878, "Reliability of Potter & Brumfield MDR Relays", June 1994.
2. WCAP-13900, "Extension of Slave Relay Surveillance Test Intervals", April 1994.
3. License Amendment 184/186, January 3, 2006.
4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.
5. RG 1.194, “Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants,” June 2003.

B 3.3 INSTRUMENTATION

B 3.3.8 Fuel Building Ventilation System (FBVS) Actuation Instrumentation

BASES

BACKGROUND	The FBVS ensures that radioactive materials in the fuel building atmosphere following 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) are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.13, "Fuel Handling Building Ventilation System." The system initiates filtered ventilation of the fuel building automatically following receipt of a high radiation signal from the Spent Fuel Pool Monitor or from the New Fuel Storage Vault Monitor. Initiation may also be performed manually as needed from the main control room or fuel handling building. High radiation, from either of the two monitors, provides FBVS initiation. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the fuel building.
APPLICABLE SAFETY ANALYSES	The FBVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident involving handling recently irradiated fuel are filtered and adsorbed prior to being exhausted to the environment. This action reduces the radioactive content in the fuel building exhaust following a fuel handling accident. The FBVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO requirements ensure that instrumentation necessary to initiate the FBVS is OPERABLE. 1. <u>Manual Initiation</u> The LCO requires two channels OPERABLE. The operator can initiate the FBVS at any time by using either of two switches, one in the control room and another in the fuel handling building. This action will cause actuation of all components in the same manner as any of the automatic actuation signals. 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.

(continued)

BASES

LCO (continued)

2. Fuel Handling Building Radiation

The LCO specifies two required Radiation Monitor channels to ensure that the radiation monitoring instrumentation necessary to initiate the FBVS remains OPERABLE.

Only the Trip Setpoint is specified for each FBVS Function in the LCO.

APPLICABILITY

The manual FBVS initiation must be OPERABLE when moving recently irradiated fuel assemblies in the fuel building, to ensure the FBVS operates to remove fission products associated with a fuel handling accident involving handling recently irradiated fuel.

High radiation initiation of the FBVS must be OPERABLE in any MODE during movement of recently irradiated fuel assemblies in the fuel building to ensure automatic initiation of the FBVS when the potential for a fuel handling accident exists. Due to radioactive decay, the FBVS actuation instrumentation is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel.

While in MODES 5 and 6 without fuel handling involving recently irradiated fuel in progress, the FBVS instrumentation need not be OPERABLE since the limiting fuel handling accident cannot occur. However, the risk shall be managed, consistent with 10 CFR 50.65 and NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants”, during movement of non-recently irradiated fuel by maintaining the capability to monitor any release for a postulated fuel handling accident from the fuel handling building. (References 2 and 3)

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a CFT and/or CHANNEL CALIBRATION, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered. Drift can also be observed during a CHANNEL CHECK or CFT and if observed would prompt action to correct the discrepancy.

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 3.3.8-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

(continued)

BASES

ACTIONS (continued)

A.1.1, A.1.2.1, A.1.2.2, and A.1.3

Condition A applies to the radiation monitor functions, and the manual function. Condition A applies to the failure of one or more radiation monitor channels, or a single manual channel. If one or more channels or trains are inoperable, movement of recently irradiated fuel may continue for a period of 30 days. If movement of recently irradiated fuel continues, an appropriate portable continuous monitor with the same setpoint, or an individual qualified in radiation protection procedures with a dose rate monitoring device must be in the spent fuel pool area immediately and, one FBVS train must be placed in the Iodine Removal mode of operation immediately. This effectively accomplishes the actuation instrumentation function and places the area in a conservative mode of operation or provides appropriate monitoring for continued fuel movement.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A has not been met and recently irradiated fuel assemblies are being moved in the fuel building. Movement of recently irradiated fuel assemblies in the fuel building must be suspended immediately to eliminate the potential for events that could require FBVS actuation.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which FBVS Actuation Functions.

SR 3.3.8.1

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.3.8.1 (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.2

A CFT is performed on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the FBACS actuation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.3 - Not used

SR 3.3.8.4

SR 3.3.8.4 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. In some instances, the test includes actuation of the end device (e.g., 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.

SR 3.3.8.5

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Not Used.
2. License Amendment 184/186, January 3, 2006.
3. PG&E Letter DCL-05-124

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 averaged to come up with a value for comparison 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. Indications of temperature are averaged to determine a value for comparison 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 is consistent with that assumed for DNB analyses. Flow rate indications from the plant computer or RCS flow rate indicators are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the DNB limits to be approached. Operation for significant periods of time outside the limits on RCS flow, pressurizer pressure and average RCS temperature increases the likelihood of a fuel cladding failure if a DNB limited event were to occur.
APPLICABLE SAFETY ANALYSES	The requirements of this LCO are consistent with the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated consistent with the limits of this LCO will result in meeting the DNBR correlation limit. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criterion. The analyzed transients 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)." The pressurizer pressure limit, RCS average temperature limit, and RCS flow limit specified in the COLR are consistent with the analytical limits used in the safety analyses with allowance for measurement 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, based on a maximum steam generator tube plugging level of 10%, is retained in the TS LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

(continued)

BASES

LCO (continued)	Use of the cold leg elbow tap method to measure RCS flow at approximately 100% RTP at the beginning of cycle includes a measurement uncertainty for the control board RCS flow rate indicators (which bounds the use of the plant process computer). This method is based on the utilization of twelve RCS cold leg elbow taps correlated to the four baseline precision heat balance measurements during Cycles 1 and 2 for each unit. Correlation of the flow indication channels with the flow calorimetric measurements performed during Cycles 1 and 2 is documented in WCAP-15113, Revision 1 (Ref 2.). Use of the cold leg elbow tap method provides an alternative to performance of a precision flow calorimetric to measure RCS flow and was approved by the NRC in amendments 161/162. The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location and have been adjusted for instrument error.
APPLICABILITY	In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure the DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

(continued)

BASES

APPLICABILITY (continued)

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational pressure 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.

Another set of limits on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." Those limits 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 reduce the potential for violation of the accident analysis limits.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition reduces the potential for violation of the accident analysis limits. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

(continued)

BASES (continued)

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. The term "indicated RCS total flow," above, is used to distinguish between the "measured RCS total flow" determined in SR 3.4.1.4.

SR 3.4.1.4

SR 3.4.1.4 has two surveillance requirements, one for the CHANNEL CALIBRATION of the RCS flow indicators and the other for measurement of RCS total flow rate. Measurement of RCS total flow rate by using the cold leg elbow tap methodology allows the installed RCS flow instrumentation to be normalized and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.1.4 (continued) The second part of this surveillance is the routine CHANNEL CALIBRATION of the RCS flow indication instrumentation. The routine calibration of the flow instrumentation ensures that the channels are within the necessary range and accuracy for proper flow indication. 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. WCAP-15113, Revision 1, "RCS Flow Measurement Using Elbow Tap Methodology at Diablo Canyon Units 1 and 2," April, 2002.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

APPLICABLE SAFETY ANALYSES

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 condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, 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 (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 ($k_{eff} \geq 1.0$) with an operating loop 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 3.1.8, "PHYSICS TESTS, Exceptions, MODE 2" permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.
ACTIONS	<u>A.1</u> If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $k_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with $k_{eff} < 1.0$ in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.4.2.1</u> RCS loop average temperature is required to be verified at or above 541°F every 12 hours. The SR to verify RCS loop average temperatures every 12 hours is frequent enough to prevent inadvertent violation of the LCO and takes into account indications and alarms that are continuously available to the operator in the control room. If the T_{avg}-T_{ref} deviation were to alarm, the specific alarm response procedure would provide an increased frequency of monitoring. Following the clearance of the alarm, the frequency returns to 12 hours to monitor RCS T_{avg}. (continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.2.1 (continued) 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	1. UFSAR, Chapter 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PRESSURE TEMPERATURE LIMITS REPORT (PTLR) contains pressure/temperature (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 references the PTLR which 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 PTLR limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. The NRC reviewed and approved methodology to be applied to determine P/T Limits is documented in the Administrative Controls Section 5.6.6.

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

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with the methodology identified in Section 5.6.6. The operating P/T limit curves will be adjusted, as necessary, in agreement with the evaluation findings based on methods used in the PTLR.

(continued)

BASES

BACKGROUND (continued)	The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions. The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls. The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality." The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components.
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. Administrative Controls Section 5.6.6, identifies the NRC reviewed and approved methodology for determining the P/T limits. 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).
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.

(continued)

BASES

LCO (continued)

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

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

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

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

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

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and 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.

(continued)

BASES (continued)

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

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

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

B.1 and B.2

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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. (Note that Action B.1 is not required when in MODE 4). A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours.

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

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

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

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 3), 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.4.3.1 Verification that operation is within the PTLR limits is required when RCS pressure and temperature conditions are undergoing planned changes. The Surveillance Frequency is 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 plant procedure for ending the activity is satisfied. This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.
REFERENCES	1. Not Used 2. 10 CFR 50, Appendix G. 3. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E. 4. NRC Generic Letter 96-03, "Relocation of the Pressure Temperature Curves and Low Temperature Overpressure Protection System Limits," January 31, 1996.

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 four 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 core and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.
APPLICABLE SAFETY ANALYSES	Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service. All of the accident/safety analyses performed at RTP assume that all four RCS loops are in operation as an initial condition. Some accident/safety analyses have been performed at zero power conditions assuming only two RCS loops are in operation to conservatively bound lower modes of operation. The uncontrolled Rod Control Cluster Assembly (RCCA) Bank withdrawal from subcritical event is included in this category. While all accident/safety analyses performed at full rated power assume that all RCS loops are in operation, selected events examine the effects resulting from a loss of RCP operation. These include the complete and partial loss of forced

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	RCS flow, RCP rotor seizure, and RCP shaft break events. For each of these events, it is demonstrated that all the applicable safety criteria are satisfied. For the remaining accident/safety analyses, operation of all four RCS loops during the transient up to the time of reactor trip is assured thereby ensuring that all the applicable acceptance criteria are satisfied. Those transients analyzed beyond the time of reactor trip were examined assuming that a loss of offsite power occurs which results in the RCPs coasting down. The plant is designed to operate with all RCS loops in operation to maintain DNBR above the Safety Limit value 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 DNB, four pumps are required at rated power. An OPERABLE RCS loop consists of one OPERABLE RCP for heat transport and the associated OPERABLE SG, with a water level within the limits specified in SR 3.4.5.2, except for operational transients. A RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.
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.

(continued)

BASES

APPLICABILITY (continued)	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	<u>A.1</u> If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.4.4.1</u> This SR requires verification that each RCS loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
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 four 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 core 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 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. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with the Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops-MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with the Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

When the Rod Control System is not capable of rod withdrawal, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure that redundancy for heat removal is maintained.

The Note permits all RCPs to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are required to be performed without flow or pump noise. 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 must be revalidated by conducting the test again.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet 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.

(continued)

BASES (continued)

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with the Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.4.4, "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 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 (RHR) System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If the required RCS loop is not in operation and the Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to place the Rod Control System in a condition incapable of rod withdrawal, (e.g., de-energize all CRDMs by opening the RTBs or de-energizing the motor generator

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

(MG) sets.) When the Rod Control System is capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must not be capable of rod withdrawal. The Completion Time of 1 hour to restore the required RCS loop to operation or to defeat the Rod Control System is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

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

If four RCS loops are inoperable or no RCS loop is 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 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.4.5.1 This SR requires verification that the required loops are in operation. Verification may include 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 3.4.5.2 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 ≥ 15% for required RCS loops. If the SG secondary side narrow range water level is < 15%, 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 RCPs are 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 RCPs. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.
REFERENCES	None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops — MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four 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 core 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. For RHR operation, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, a RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR loop circulates the water through the RCS at a sufficient rate to remove decay heat and to prevent boric acid stratification.

Although NUREG-1431 uses "loop" to define RHR system requirements, past practice is use of "train", consistent with ECCS discussions of train availability and redundancy. Plant procedures are written using "train". The designations of "loop" and "train" are considered synonymous.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is 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 have been identified in 10 CFR 50.36(c)(2)(ii) as important contributors to risk reduction.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs or RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. 1 hour is adequate to perform the 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 test procedures:

a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet 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.

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 ≤ LTOP arming temperature specified in the PTLR (Reference 1) Note 2 also includes a DCPP plant specific alternate condition under which a RCP may be started in MODE 4 and in MODE 5 with the loops filled. Note that RCPs may be "bumped" following a condition of RCS depressurization to establish "loops filled" condition. The Note specifies that a RCP may be started if the pressurizer water level is less than 50%. This option of RCP start with pressurizer water level less than 50% supports plant operational flexibility. The open volume in the pressurizer provides space to sustain reactor coolant thermal swell without incurring a possible excessive pressure transient due to energy additions from the SG secondary water. The purpose of conditions to allow initial RCP start when none is running is to prevent a possible low temperature RCS overpressure event due to a thermal transient when a RCP is started. The condition of SG/RCS

(continued)

BASES

LCO (continued)	temperature difference limits the available relative energy source and the pressurizer level condition provides an expansion volume to accommodate possible reactor coolant thermal swell. These conditions are intended to prevent a low temperature overpressure event due to a thermal transient when a RCP is started. An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG, which has the minimum water level specified in SR 3.4.6.2. Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required. A RHR loop is in operation when the pump is operating and providing forced flow through the loop. Because a loop can be operating without being OPERABLE, the LCO requires at least one loop OPERABLE and in operation. Management of gas voids is important to RHR System OPERABILITY.
APPLICABILITY	In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations. Operation in other MODES is covered by: LCO 3.4.4, "RCS Loops - MODES 1 and 2"; LCO 3.4.5, "RCS Loops - MODE 3"; LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled"; 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 and A.2</u> If one required RCS loop is inoperable and two RHR loops are inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS loop or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS loop or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, 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 (≤ 200°F) rather than MODE 4 (> 200°F to < 350°F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

B.1 and B.2

If no loop is OPERABLE or 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.

Boron dilution requires forced RCS circulation from at least one RCP for proper mixing, so that an inadvertent criticality may be prevented. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification that one RCS loop or RHR loop is in operation. Verification may include 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 ≥ 15%. If the SG secondary side narrow range water level is < 15%, 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.

SR 3.4.6.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.4 (continued)

discharge of a pump), the Surveillance is not met. If the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

This SR is modified by a Note that states the SR is not required to be performed until 12 hours after entering MODE 4. In a rapid shutdown, there may be insufficient time to verify all susceptible locations prior to entering MODE 4.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. Diablo Canyon Power Plant Pressure and Temperature Limits Report.

2. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, "Generic Letter 2008-01, Managing Gas Accumulation," Using the Consolidated Line Item Improvement Process.

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 of 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 are specified as a backup means for redundancy. Even though the SG 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 two SGs with secondary side water levels above 15% to provide an alternate method for decay heat removal via natural circulation.
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) have been identified in 10 CFR 50.36(c)(2)(ii) as important contributors to risk reduction.

(continued)

BASES (continued)

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 two SGs with secondary side water level ≥ 15%. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ 15%. Should the operating RHR loop fail, the SGs 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 tests that are required to be performed without flow or pump noise. 1 hour is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet 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.

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 any RCS cold leg temperature ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR. Note that RCPs may be "bumped" following a condition of RCS depressurization to establish "loops filled" condition.

Note 3 also includes an OR condition for starting a RCP. This condition is a DCPP plant specific alternate condition under which a RCP may be started in MODE 4 and in MODE 5 with the loops filled.

(continued)

BASES

LCO (continued)

The Note specifies that a RCP may be started if the pressurizer water level is less than 50%. This option of RCP start with pressurizer water level less than 50% supports plant operational flexibility. The open volume in the pressurizer provides space to sustain reactor coolant thermal swell without incurring a possible excessive pressure transient due to energy additions from the S/G secondary water. The purpose of conditions to allow initial RCP start when none is running is to prevent a possible low temperature RCS overpressure event due to a thermal transient when a RCP is started. The condition of SG/RCS temperature difference limits the available relative energy source and the pressurizer level condition provides an expansion volume to accommodate possible reactor coolant thermal swell. These conditions are intended to prevent a low temperature overpressure event due to a thermal transient when a 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.

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. Management of gas voids is important to RHR System OPERABILITY.

APPLICABILITY

"Loops filled" is a condition in which natural circulation can be used as a backup means of decay heat removal if forced circulation via RHR is lost. RCS loops are considered filled when the RCS is capable of being pressurized to at least 150 psig, no gas has been directly injected into the RCS, and the RCS has not been drained below 111 ft (Ref. 2 and 4). In addition to these requirements, crediting heat removal via natural circulation requires at least two steam generators filled to ≥15% narrow range level and vented, or capable of being vented, to the atmosphere, and auxiliary feedwater available to add water to the relied-upon steam generators (Ref. 1). A loops filled condition is established at the completion of steam generator U-tube vacuum refill or after "bumping" RCPs.

In MODE 5 with 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 two SGs is required to be ≥ 15%.

(continued)

BASES

APPLICABILITY (continued)	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).

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels < 15%, 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 levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no 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. To prevent inadvertent criticality during a boron dilution, forced circulation from at least one RHR pump is required to provide proper mixing and preserve the margin to criticality in this type of operation. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable 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 may include 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are ≥ 15% 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 a second 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 RHR pump. If secondary side water level is ≥ 15% in at least two SGs, 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 3.4.7.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.4 (continued)

discharge of a pump), the Surveillance is not met. If the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."
2. AR A0582812.
3. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, “Generic Letter 2008-01, Managing Gas Accumulation,” Using the Consolidated Line Item Improvement Process.
4. SAPN 51002886-03

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) have been identified in 10 CFR 50.36(c)(2)(ii) as important contributors to risk reduction.
LCO	The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet single failure considerations. Note 1 permits all RHR pumps to be removed from operation for ≤ 1 hour. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained at least 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.

(continued)

BASES

LCO (continued)	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. Management of gas voids is important to RHR System OPERABILITY.
APPLICABILITY	In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System. The "loops filled" condition requires that the RCS is capable of being pressurized to at least 150 psig, no gas has been directly injected into the RCS, and the RCS has not been drained to below 111 ft (Ref. 1 and 3). Loops filled is based on the ability to credit natural circulation as a backup means of decay heat removal, and until the above conditions are met, the "loops not filled" condition is applicable. 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). Since LCO 3.4.8 contains Required Actions with immediate Completion Times, it is not permitted to enter LCO 3.4.8 from either LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled" or from MODE 6 unless the requirements of LCO 3.4.8 are met.
ACTIONS	<u>A.1</u> If only one RHR loop is OPERABLE and in operation, 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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If no required RHR loops are OPERABLE or 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. Boron dilution requires forced circulation from at least one RHR pump for proper mixing so that inadvertent criticality can be prevented. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification that one loop is in operation. Verification may include 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 number of pumps are OPERABLE ensures that additional pumps 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 pumps. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.3 (continued)

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.4.8.3 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.
REFERENCES	1. AR A0582812. 2. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, “Generic Letter 2008-01, Managing Gas Accumulation,” Using the Consolidated Line Item Improvement Process. 3. SAPN 51002886-03

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.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system.

Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present. Safety analyses presented in the UFSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure. 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 ≤ 1600 cubic feet, which is equivalent to 90% of span, ensures that a steam bubble exists. Instrument inaccuracy is not included in this % number. 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 ≥ 150 kW, capable of being powered from either the offsite power source or the emergency power supply. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. The capability to power the heaters from an emergency power supply using bus cross-tie to an OPERABLE emergency diesel generator, if necessary, provides the means to maintain system pressure control during a loss of normal power. RCS pressure control is necessary to maintain subcooling under conditions of natural circulation flow in the primary system. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops.

(continued)

BASES (continued)

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 either the offsite power source or the emergency power supply, and if necessary, using bus cross-tie to an OPERABLE emergency diesel generator. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

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

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. The upper limit of this LCO is below the Pressurizer Water Level - High Trip at 90% of span.

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 rods fully inserted and the Rod Control System not capable of rod withdrawal (e.g., de-energize all CRDMs by opening the RTBs or de-energizing the motor - generator sets). Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours or in accordance with the Risk Informed Completion Time Program. 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 normal station powered heaters.

(continued)

BASES

ACTIONS (continued)	C.1 and C.2 If one required group of pressurizer heaters is inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.4.9.1 This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. SR 3.4.9.2 The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design 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. SR 3.4.9.3 This SR demonstrates that the heaters can be manually transferred from the normal to the emergency power supply and energized. 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.

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, 420,000 lb/hr at 2485 psig plus 3% accumulation, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves which is divided equally among the three 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 and an increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, and 4. However, in MODE 4, with one or more RCS cold leg temperatures ≤ LTOP arming temperature specified in the PTLR (Reference 6) and in MODE 5 and MODE 6 with the reactor vessel head on and the reactor vessel head closure bolts not fully de-tensioned, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ± 1% of nominal pressure tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot (which is the current DCPP practice) or if valves are set cold, 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.

(continued)

BASES

BACKGROUND (continued)	The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.
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. Feedline break; c. Loss of external electrical load; d. Loss of normal feedwater; e. Loss of all AC power to station auxiliaries; f. Locked Reactor Coolant Pump (RCP) rotor; and g. Rod cluster control assembly ejection Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation is required in events b c, d, e and f (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).
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 upper and lower pressure tolerance limits are based on the ± 1% of nominal pressure tolerance requirements (Ref. 1) for lifting pressures above 1000 psig. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when any RCS cold leg temperature is ≤ LTOP arming temperature specified in the PTLR, or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head closure bolts fully de-tensioned.

The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this time frame.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperatures ≤ LTOP arming temperature specified in the PTLR within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With any RCS cold leg temperature at or

(continued)

BASES

ACTIONS	B.1 and B.2 (continued) below LTOP arming temperature specified in the PTLR, 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. The ASME Code, Section XI (Ref. 4), requires that safety and relief tests be performed in accordance with ASME OM Code (Ref. 5.). No additional requirements are specified. The pressurizer safety valve setpoint is +2.3%/-3% for OPERABILITY; however the valves are reset to ± 1% of nominal pressure of 2485 psig 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. 4. ASME, Boiler and Pressure Vessel Code, Section XI. 5. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2001 Edition including 2002 and 2003 Addenda. 6. Diablo Canyon Power Plant Pressure and Temperature Limits Report.

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 operated valves that are controlled to open when the pressurizer pressure increases above their actuation setpoint and to close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

DCPP design includes three air operated pressurizer PORVs. Two of these PORVs have been designated as "Class I". These two valves provide the reactor vessel low temperature overpressure protection and mitigate the consequences of a spurious operation of the safety injection system at power event and the main feedwater line break event, and provide the means to depressurize the RCS following a steam generator tube rupture (SGTR). These functions must be accomplished under accident analyses assumptions such as loss of offsite power. Consequently, a PG&E Design Class I nitrogen backup system to the non-PG&E Design Class I air supply is provided for the two Class I PORVs. The identification of Class I is used to make a distinction between these two PORVs that must provide a PG&E Design Class I function as opposed to the third remaining PORV that is designated as ”non-Class I”. TS 3.4.12 for LTOP applies to the two Class I PORVs but not to the non-Class I PORV.

The non-Class I PORV is associated with plant transients as compared to accident mitigation. Although mitigation is not its primary purpose, the valve may be used for those functions also, although not credited for operation.

The three PORVs are the same design. The PORV that is not designated as Class I may be used, when instrument air is available, to control RCS pressure similarly to the Class I PORVs. However, two Class 1 PORVs satisfy the function, with redundancy, therefore continued operation with the non-Class I PORV unavailable for RCS pressure control is allowed as long as the block valve or PORV can be closed to maintain the RCS pressure boundary. The plant has the capability to sustain a 50% load reduction without a reactor trip with two PORVs available.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The three MOV block valves are the same design. The block valves are used to isolate the PORVs in case of excessive seat 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.

(continued)

BASES

BACKGROUND (continued)	The PORVs may be manually cycled and are equipped with circuitry for automatic actuation. The automatic mode is the preferred configuration, as this provides pressure relieving capability without reliance on operator action. The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permits performance of surveillances on the block 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 Class 1E 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 PORV block valves are all powered from separate Class 1E buses. The plant has three 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 Pressure - High reactor trip setpoint up to and including the design step-load decrease. In addition, the PORVs minimize challenges to the pressurizer safety valves and the two Class I PORVs are used for low temperature overpressure protection (LTOP). Refer to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."
APPLICABLE SAFETY ANALYSES	Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal or auxiliary pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes manual operator actions 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. For the SGTR event, 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. For both the spurious operation of the safety injection system at power event (a Condition II event) and the major rupture of a main feedwater pipe accident (a Condition IV event), the safety analysis credits operator actions from the main control room to lower and control pressurizer water level and to open a PORV block valve (assumed to be initially closed) and assure the availability of at least one PORV for automatic pressure relief. Analysis results indicate that water relief through the pressurizer safety valves, which could result in a loss of reactor coolant pressure boundary integrity if the safety valves do not reseat, is precluded if operator actions are taken within the times assumed in

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	the analysis. The assumed operator action times conservatively bound the times measured during simulator exercises. Therefore, automatic PORV operation is an assumed safety function in MODES 1, 2, and 3. The PORVs are equipped with automatic actuation circuitry and manual control capability. The PORVs are considered OPERABLE in either the automatic or manual mode, as long as the automatic actuation circuitry is OPERABLE and the PORVs can be made available for automatic pressure relief by timely operator actions to open the associated block valves (if closed) and assure the PORV handswitches are in the automatic position. The automatic mode is the preferred configuration, as this provides the required pressure relieving capability without reliance on operator action. 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. This LCO also requires the PORVs and their automatic actuation circuitry to be OPERABLE, in conjunction with the capability to manually open their associated block valves and assure the availability of the PORVs for automatic pressure relief, to mitigate the effects associated with the spurious operation of the safety injection system at power event and the major rupture of a main feedwater pipe accident. The PORVs are considered OPERABLE in the automatic or manual mode, as long as the automatic actuation circuitry is OPERABLE and the PORVs can be made available for automatic pressure relief by timely operator actions to open the associated block valves (if closed) and assure the PORV handswitches are in the automatic position. The automatic mode is the preferred configuration, as this provides the required pressure relieving capability with reliance on operator actions. By maintaining the PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open and energized, or closed and energized, with the capability to be cycled, since the required safety functions of the block valve are accomplished by manual operation to cycle the block valve. Although typically open to allow PORV operation, the block valve may be OPERABLE when closed to isolate the flow path of an inoperable PORV because of excessive seat leakage. Isolation of an OPERABLE PORV does not render that PORV or block valve inoperable, provided the automatic pressure relief function remains available with timely operator actions to open the associated block valve, if closed, and assure the PORV handswitch is in the automatic position. The block valves are available to isolate the flow path through either a failed open PORV or a PORV with excessive seat leakage. Satisfying the LCO helps minimize challenges to fission product barriers.

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, and 3, the PORVs are required to be OPERABLE to mitigate a SGTR and spurious operation of the safety injection system at power event, and the main feedwater line break event, and the block valves are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. PORV OPERABILITY in MODES 1, 2, and 3 will also minimize challenges to the pressurizer safety valves. 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. OPERABILITY of the PORVs requires them to be capable of both manual and automatic operation. The PORV setpoint is reduced for LTOP in MODES 4, 5, and 6 with the reactor vessel head in place and the reactor vessel head closure bolts not fully de-tensioned. LCO 3.4.12 addresses the PORV requirements in these MODES.
ACTIONS	A Note 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). <u>A.1</u> PORVs may be inoperable and capable of automatic pressure relief or 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 valves is required to be closed but power must be maintained to the associated block valves, since removal of power would render the block valve inoperable. Credit for automatic PORV operation is taken in the safety analysis. However, the PORVs are considered OPERABLE in either the manual or automatic mode, as long as the automatic actuation circuitry is OPERABLE and the PORV can be made available for automatic pressure relief by timely operator actions. Although a PORV may be designated inoperable, it may be available for automatic pressure relief and capable of being manually opened and closed, and therefore able to perform its required safety functions. PORV inoperability solely due to excessive seat leakage does not prevent automatic and manual use and does not create the possibility for a small break LOCA. For these reasons, the block valve may be closed but the ACTION requires power be maintained to the valve. This Condition is only intended to permit operation of the plant for a limited period of time not to extend beyond the next refueling outage

(continued)

BASES

ACTIONS

A.1 (continued)

(MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition. Normally, the PORVs should be available for automatic mitigation of overpressure events and should be returned to OPERABLE and automatic actuation status prior to entering startup (MODE 2).

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

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

If one PORV is inoperable and not capable of automatic pressure relief or 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 for Required Actions B.1 and B.2 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 PORV cannot be restored to OPERABLE status, it must be isolated within the specified time of 1 hour. Because at least one Class I PORV remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status if it is Class I. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the valve is the non-Class I PORV, there is no required Completion Time. If the Class I PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply as required by Condition D.

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

If one PORV 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 PORV control switch has three positions; open, close, and auto. Placing the PORV in manual control, if required in ACTION C, is accomplished by positioning the switch out of the auto control mode. 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 associated PORV in manual control.

(continued)

BASES

ACTIONS

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

This action is taken to avoid the potential for a stuck open PORV if the valve were to open under automatic control 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. If the inoperable block valve is associated with a Class 1 PORV, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The time allowed to restore the Class I PORV block valve is based upon the Completion Time for restoring an inoperable Class I PORV in Condition B, since the PORVs are not capable of mitigating a SGTR or spurious operation of the safety injection system at power event, or a main feedwater line break accident when inoperable. If the block valve is restored within the Completion Time, the PORV will be transferred to the automatic mode of operation. If the block valve cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply as required by Condition D.

If the inoperable block valve is associated with the non-Class I PORV, the block valve may be closed and the power removed. The 72 hour Completion Time for closing the block valve is the same applied in Required Action C.2. This recognizes that some restoration work may be required since the block valve is inoperable.

Restoration of the non-class I PORV block valve to OPERABLE status is not required because the non-Class I PORV is not required to be available, although having the valve closed impairs the load rejection design capability. Therefore, once the block valve has been closed per Required Action C.3, Completion Time requirements of Condition D do not apply.

If the block valve cannot be placed in the closed position, per Required Action C.3, Condition D applies and the unit must be taken to MODE 4 until the block valve is restored or closed.

The Required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition.

(continued)

BASES

ACTIONS (continued)

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

If the Required Action of Condition A, B, or C is not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4, 5, and 6 with the reactor vessel head closure bolts not fully de-tensioned, maintaining Class I PORV OPERABILITY is required by LCO 3.4.12.

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

If more than one Class I PORV is inoperable for reasons other than excessive seat leakage, it is necessary to either restore at least one valve, within the Completion Time of 1 hour, or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If one Class I PORV is restored and one Class I PORV remains inoperable, then the plant will be in Condition B with the time clock started at the original declaration of having two Class I PORVs inoperable. If no Class I PORVs are restored within the Completion Time, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4, 5, and 6 with the reactor vessel head closure bolts not fully de-tensioned, maintaining Class I PORV OPERABILITY is required by LCO 3.4.12.

(continued)

BASES

ACTIONS (continued)

F.1, F.2, F.3, and F.4

If more than one PORV block valve is inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control and restore at least one block valve within 2 hours and restore the remaining block valve within 72 hours. The PORV control switch has three positions; open, close and auto. Placing the PORV in manual control, if required in ACTION F, is accomplished by positioning the switch out of the auto control mode. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation. Alternatively, a Completion Time to restore the remaining block valve can be determined in accordance with the Risk Informed Completion Time Program.

If the inoperable block valve is associated with the non-Class I PORV, the block valve may be closed and the power removed. The 72 hour Completion Time for closing the block valve is the same time used in Required Action F.3. This recognizes that some restoration work may be required since the block valve is inoperable. Restoration of the non-class I PORV block valve to OPERABLE status is not required because the non-Class I PORV is not required to be available, although having the valve closed impairs the load rejection design capability. Therefore, once the block valve has been closed per Required Action F.4, Completion Time requirements of Condition G do not apply.

If the block valve can not be placed in the closed position per Required Action F.4, Condition G applies until the block valve is restored or closed.

The required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition.

(continued)

BASES

ACTIONS (continued)

G.1, G.2 and G.3

If the Required Actions of Condition F are not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4, 5, and 6 with the reactor vessel head closure bolts not fully de-tensioned, maintaining Class I PORV OPERABILITY is required by LCO 3.4.12.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be 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.

The Note modifies this SR by stating that it is not required to be performed with the block valve closed in accordance with the Required Action of this LCO. Opening the block valve in this condition increases the risk of an unisolable leak from the RCS since the PORV is already inoperable.

SR 3.4.11.2

SR 3.4.11.2 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. Operating experience has shown that these valves usually pass the surveillance when performed at the required Inservice Testing Program frequency. The frequency is acceptable form a reliability standpoint.

The Note modifies this SR to allow entry into an operation in MODE 3 prior to performing the SR. This allows the surveillance to be performed in MODE 3 or 4.

The Note that modified 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. In accordance with Reference 4, administrative controls require this test be performed in MODE 3 or 4 to adequately simulate operating temperature and pressure effects on PORV operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.3

Verifying OPERABILITY of the PG&E Design Class I nitrogen supply for the Class I PORVs may be accomplished by:

a. Isolating and venting the normal air supply, and

b. Verifying that any leakage of the PG&E Design Class I backup nitrogen system is within its limits, and

c. Operating the Class I PORVs through one complete cycle of full travel.

Operating the solenoid nitrogen control valves and check valves on the nitrogen supply system and operating the Class I PORVs through one complete cycle of full travel ensures the nitrogen backup supply for the Class I PORV operates 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.

SR 3.4.11.4

Performance of a COT is required on each required Class I PORV to verify and, as necessary, adjust its lift setpoint. PORV actuation could depressurize the 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.

SR 3.4.11.5

Performance of a CHANNEL CALIBRATION on each required Class I 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. Not Used.
2. UFSAR, Sections 15.2 and 15.4.
3. ASME, Code for Operation and Maintenance of Nuclear Power Plants, 2001 Edition including 2002 and 2003 Addenda.
4. Generic Letter 90-06, "Resolution of Generic Issue 70, 'Power-Operated Relief Valve and Block Valve Reliability,' and generic issue 94, 'Additional Low-Temperature Overpressure Protection for Light-Water Reactors,' Pursuant to 10 CFR 50.54(f)," June 25, 1990.

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 pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PRESSURE TEMPERATURE LIMITS REPORT (PTLR) (Reference 12) provides the allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperatures during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES. The PTLR also provides LTOP temperature restrictions for operation of the reactor coolant pumps, safety injection (SI) pumps, ECCS centrifugal charging pumps, and ECCS injection flow path.

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 after temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits. Further, the normal charging pump (NCP) (i.e., Centrifugal Charging Pump No. 3, (CCP-3)) shall be aligned to the LTOP orifice, when it is capable of injecting into the RCS, during LTOP conditions.

This LCO provides RCS overpressure protection by limiting to a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all SI pumps and one ECCS centrifugal charging pump (CCP) incapable of injection into the RCS and isolating the accumulators.

A maximum of one ECCS CCP shall be capable of injecting into the RCS, and the NCP shall be aligned to LTOP orifice when it is capable of injecting into the RCS, when any RCS cold leg temperature is less than or equal to the LTOP arming temperature.

(continued)

BASES

BACKGROUND (continued)

The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

The pressurizer has three Power Operated Relief Valves. Two of the three are classified as PG&E Design Class I and are designated as "Class I" for LTOP pressure protection. All the PORVs are air operated. These two PG&E Design Class I PORVs have a nitrogen gas backup to the non-PG&E Design Class I air supply. Either air supply or nitrogen supply will satisfy PORV operability requirements.

The three PORVs are the same design. The PORV that is designated as "non-Class I" may be used, when instrument air is available, to control RCS pressure similarly to the Class I PORVs although the non-Class I PORV does not receive an automatic open signal like the LTOP designated valves. Therefore, because no credit is taken for its operation for LTOP, continued operation with the non-Class I PORV unavailable for RCS pressure control is allowed as long as the associated block valve or non-Class I PORV can be closed to maintain the RCS pressure boundary.

In MODE 4 with the RHR loops in operation and in MODES 5 and 6, the operating RHR loop, connected to the RCS, can provide pressure relief capability through the RHR suction line relief valve. This capacity for RCS pressure relief is not assumed in the PTLR LTOP considerations and analyses and is not included in the LCO, ACTIONS, or Surveillances.

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the 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 ECCS CCP for makeup in the event of loss of inventory, then RHR pumps can be made available through manual actions.

Additionally, ECCS CCPs in excess of the above limitations can be momentarily capable of injection into the RCS for swapping of inservice ECCS CCPs. This condition is acceptable based on the operator's attentiveness to RCS pressure during the pump switch over and the capability of the operator to limit a pressure increase.

The LTOP System for pressure relief consists of two Class I PORVs with reduced lift settings or a depressurized RCS and an RCS vent of sufficient size. Two RCS Class I PORVs are required for redundancy. One RCS Class I PORV has adequate relieving capability to prevent overpressurization from the allowable coolant input capability.

(continued)

BASES

BACKGROUND (continued)

PORV Requirements

As designed for the LTOP System, each Class I PORV is signaled to open if the RCS pressure approaches a limit determined by the LTOP actuation setpoint. The evolution of RHR cooldown with no RCP

forced circulation represents a condition where variation in RCS cold leg temperatures may occur. The RCS loop 2 and 3 wide range cold leg temperature indications provide the temperature input signal. Temperature indications from these two loops were selected to constitute a good representation of the overall four loop temperatures. However, in the event that only one RHR loop is in operation, temperature indications from RCS cold legs 2 and 3 will provide indication from a RCS loop into which the cooler water from the RHR discharge is entering. All four cold leg temperature indications are in the control room and provide a loop by loop comparison for the operator.

The LTOP system is placed into service and the block valves verified to be open by procedure at a RCS pressure of about 350 psig. This is an administrative action, not required by TS. However, if LTOP has not been placed into service prior to when the RCS temperature decreases to LTOP arming temperature specified in the PTLR (Reference 12) , the LTOP enable alarm annunciates to alert the operator to place the LTOP system into service. Placing LTOP into service at this point is required to satisfy the LTOP Applicability requirements. Following being placed into service, LTOP will receive RCS temperature and pressure input. The PTLR LTOP pressure setpoint is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the LTOP value, and the temperature is lower than the enable temperature, a PORV is signaled to open. The two Class I PORVs operate individually with their own setpoints.

The PTLR specifies the setpoints for LTOP. Having the setpoints of both valves within the limits in the PTLR ensures that the Reference 1 limits, with a 10% relaxation provided by Reference 9, will not be exceeded in any analyzed event.

When a PORV opens 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.

(continued)

BASES

BACKGROUND (continued)

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure during a 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 P/T limits. The required vent capacity may be provided by one or more vent paths.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with RCS cold leg temperatures exceeding LTOP arming temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At or below the arming temperature specified in the PTLR, overpressure prevention falls to two OPERABLE RCS Class I PORVs or to a depressurized RCS and a sufficiently sized RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 4 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;

b. Charging/letdown flow mismatch;

c. Accumulator discharge.

<u>Heat Input Type Transients</u>

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 SI pumps and one ECCS CCP incapable of injection; and aligning NCP to the LTOP orifice when it is capable of injecting into the RCS;

b. Deactivating the accumulator discharge isolation valves in their closed positions; and

c. Precluding start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop and pressurizer water level is not less than 50%. LCO 3.4.6, "RCS Loops-MODE 4," and LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," provide this protection.

The Reference 13 analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when maximum mass injection capability of one ECCS CCP in conjunction with the NCP aligned to the LTOP orifice is considered. Thus, the LCO allows a maximum of one ECCS CCP OPERABLE, and the NCP aligned to the LTOP orifice when it is capable of injecting into the RCS during the LTOP MODES. Since neither one RCS relief valve nor the RCS vent can handle the pressure transient resulting from accumulator injection, when RCS temperature is low the LCO also requires accumulator isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The isolated accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

The current DCPP temperature of LTOP Applicability specified in PTLR (Reference 12) was determined in agreement with WCAP 14040 and ASME Code Case N-514. This criteria was approved for use by LA 133/131.

The consequences of a small break loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 5 and 6), requirements by having a maximum of one ECCS CCP OPERABLE and SI actuation enabled.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the P/T limit, based on References 1 and 9, as shown in the PTLR. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP transient of one ECCS CCP injecting into the RCS with the NCP aligned to the LTOP orifice when it is capable of injecting into the RCS and with RCS letdown isolated. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits, with a 10% relaxation provided by Reference 9, will be met at low temperature operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The PORV setpoints in the PTLR will be updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The PTLR discusses these examinations.

The failure of one Class I PORV is assumed to represent the worst case, single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 2.07 square inches is capable of mitigating the allowed LTOP transient. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, no SI pumps, one ECCS CCP OPERABLE, and the NCP aligned to the LTOP orifice when it is capable of injecting into the RCS, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

The RCS vent size will be 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 pathway from the RCS to the vent is also considered to be passive. The vent is considered to connect directly to the RCS. If the pathway includes devices with the potential to block the pathway, these devices must be secured to avoid blocking the vent. A PORV may be used as RCS vent if it is blocked opened by mechanical means with a vent size of at least 2.07 square inches. The associated block valve must be fully opened with the control power removed (Ref. 10).

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 RCS coolant input and pressure relief capabilities are within limits established in the LCO. Violation of this LCO could lead to the loss of low temperature overpressure mitigation capability and violation of the PTLR limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires that no SI pumps, the NCP aligned to the LTOP orifice and a maximum of one ECCS CCP (except during pump swap operations) be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and immobilized when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

(continued)

BASES

LCO (continued)

Note 1 allows two ECCS CCPs and the NCP aligned to LTOP orifice to be made capable of injecting for ≤ 1 hour during pump swap operations. One hour provides sufficient time to safely complete the actual transfer and to complete the administrative controls and surveillance requirements associated with the swap. The intent is to minimize the time when the maximum flow could be more than the combined flow from the NCP aligned to the LTOP orifice and one ECCS CCP are physically capable of injecting.

Note 2 states that the accumulator may be unisolated when the accumulator pressure is less than the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valves Surveillance to be performed only under these pressure and temperature conditions.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two RCS Class I PORVs as follows:

   A Class 1 PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

<u>OR</u>

b. A depressurized RCS and an RCS vent.

   An RCS vent is OPERABLE when open with an area of ≥ 2.07 square inches.

Either of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

The LCO is modified by a Note that permits the NCP aligned to the LTOP orifice and two ECCS CCPs capable of injecting into the RCS for one hour for pump swap operation.

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ LTOP arming temperature specified in the PTLR, in MODE 5, and in MODE 6 when the reactor vessel head is on and the vessel head closure bolts are not fully de-tensioned. RCS overpressure protection is not required in MODE 6 with the reactor vessel head closure bolts fully de-tensioned. The head is considered to be fully detensioned when all the nuts on the reactor head studs are backed off at least 0.3 inches (0.5 +/- 0.2 inches). This will provide adequate margin for pressure relief capability for a maximum ECCS injection flow when LTOP restrictions are no longer in place. A minimum of three equally spaced nuts will be retained to prevent head cocking, tilting, or separation of the upper internals from the fuel assemblies, if the head is to remain on the flange detensioned for any extended period of time.

(continued)

BASES

APPLICABILITY (continued)

The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above the limiting temperature specified in the PTLR. When the reactor vessel head is off, overpressurization cannot occur.

The PTLR 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, 3, and MODE 4 above LTOP arming temperature specified in the PTLR.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time is available for operator action to mitigate the event.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable LTOP system. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and B.1

With one or more SI pumps or two ECCS CCPs capable of injecting into the RCS, or the NCP not aligned to the LTOP orifice (when it is 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, D.1, and D.2

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required ACTION 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 > LTOP arming temperature specified in the PTLR, an accumulator pressure of 600 psig cannot exceed the P/T limits if the accumulators are fully injected. The second option to depressurize the accumulators below the P/T limits from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

(continued)

BASES

ACTIONS (continued)

E.1

In MODE 4 when any RCS cold leg temperature is ≤ LTOP arming temperature specified in the PTLR, with one required RCS Class I PORV inoperable, the RCS Class I PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two RCS Class I PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the RCS Class I 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.

F.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 7). Thus, with one of the two RCS Class I PORVs inoperable in MODE 5 or in MODE 6 with the head on and the vessel head closure bolts not fully de-tensioned, the Completion Time to restore two valves to OPERABLE status is 24 hours.

The Completion Time represents a reasonable time to investigate and repair several types of relief valve failures without exposure to a lengthy period with only one OPERABLE RCS Class I PORV to protect against overpressure events.

G.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required RCS Class I 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 plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

(continued)

BASES (continued)

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, no SI pumps and one ECCS CCP are verified capable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and their breakers open. Verification that each accumulator is isolated is only required when accumulator isolation is required as stated in Note 1 to the LCO. Further, the NCP aligned to the LTOP orifice when it is capable of injecting into the RCS is also verified during LTOP conditions.

The SI pumps and one ECCS CCP are rendered incapable of injecting into the RCS for example, through opening the DC knife switch supplying the pumps breaker's control power or removing the power from the pumps by racking the breakers out under administrative control or by isolating the discharge of the pump by closed isolation valves with power removed from the operators or by a manual isolation valve secured in the closed position.

An alternate method of providing low temperature overpressure protection may be employed to prevent a pump start that could result in an injection into the RCS. An inoperable pump may be energized for test or for accumulator fill provided the discharge of the pump is isolated from the RCS by closed isolation valve(s) with power removed from the valve operator(s), or by manual isolation valve(s) sealed in the closed position. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.4

Not Used

SR 3.4.12.5

The RCS vent of ≥ 2.07 square inches is proven OPERABLE by verifying its open condition.

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 3.4.12.5 (continued)

Any passive vent path arrangement need only be open when required to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of LCO 3.4.12.b.

SR 3.4.12.6

The Class I PORV block valve must be verified open every 72 hours to provide the flow path for each required Class I PORV to perform its function when actuated. The valve must be remotely verified open in the main control room. This surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

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

SR 3.4.12.7

Not Used

SR 3.4.12.8

The SR Note states that the SR is not required to be performed until 12 hours after decreasing any RCS cold leg temperature to ≤ LTOP arming temperature specified in the PTLR.

The SR may be performed prior to reaching ≤ LTOP arming temperature and must be current (within 31 days) to meet this surveillance requirement. If not performed prior to reaching LTOP temperature, the test must be performed within 12 hours after entering the LTOP MODES. The 12 hour allowance considers the unlikelihood of a low temperature overpressure event during this time.

Following the initial SR, while remaining in the Applicable LTOP MODE, the SR will be performed thereafter on each required Class I PORV to verify and, as necessary, adjust its lift setpoint. The COT will verify the setpoint is within the PTLR allowed limits in the PTLR. PORV actuation could depressurize the 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.9

Performance of a CHANNEL CALIBRATION on each required Class I 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. Not Used
4. UFSAR, Chapter 5.
5. 10 CFR 50, Section 50.46.
6. 10 CFR 50, Appendix K.
7. Generic Letter 90-06.
8. Not Used
9. ASME Code Case N-514.
10. AR A0625429
11. AR A0589860
12. Diablo Canyon Power Plant Pressure and Temperature Limits Report
13. PG&E Letter DCL-16-028, License Amendment Request 16-02, “License Amendment Request To Revise Technical Specification 3.4.12, "Low Temperature Overpressure Protection (LTOP) System",” dated March 23, 2016.
14. SAPN 50970026-12

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

10 CFR 50, Appendix A, GDC 16, 1967 (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.

Possible leakage from a Control Rod Drive Mechanism (CRDM) canopy seal weld may be construed as either identified or unidentified LEAKAGE but not construed as pressure boundary LEAKAGE in accordance with Westinghouse letter PGE-88-622.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leak tight. 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).

(continued)

BASES (continued)

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. Safety analyses for design basis events that model primary to secondary LEAKAGE result in steam discharge to the atmosphere. The safety analyses for events resulting in steam discharge to the atmosphere, other than SGTR, assume that primary to secondary LEAKAGE from all SGs is 0.75 gpm (Standard Temperature and Pressure) under accident conditions. For conservatism, the SLB analysis assumes that the total 0.75 gpm tube leakage is assigned to the faulted steam generator. 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 SLB safety analysis for the faulted SG.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, 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 SGTR (Ref. 3) is more limiting for radiological releases at the site boundary. The radiological dose analysis assumes loss of off-site power at the time of reactor trip with no subsequent condenser cooling available. The steam generator (SG) PORV for the SG that has sustained the tube rupture is assumed to fail open for 30 minutes, at which time the operator closes the block valve to the PORV. The dose consequences resulting from the SGTR accident are within the limits defined in 10 CFR 50.67 (Ref. 6).

The SLB is more limiting for site radiation releases for events other than SGTR. The dose consequences resulting from the SLB accident are within the limits defined in 10 CFR 50.67.

The safety analysis for RCS main loop piping for GDC 4, 1987 (Ref. 1) assumes 1 gpm unidentified leakage and monitoring per RG 1.45 (Ref. 2) are maintained (Ref. 4 and 5).

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES (continued)

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, gaskets, or the CRDM canopy seal welds is not pressure boundary LEAKAGE. Pressure boundary LEAKAGE is defined in TS 1.1 as LEAKAGE (except SG LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall. A "non-isolable" RCS leak is one that is not capable of being isolated from the RCS using installed automatic or accessible manual valves.

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). Identified LEAKAGE does not include LEAKAGE from portions of the Chemical and Volume Control System outside of containment that can be isolated from the RCS. LEAKAGE of this nature may be reviewed for possible impact on the Primary Coolant Sources Outside Containment program. Violation of this LCO could result in continued degradation of a component or system.

(continued)

BASES

LCO
(continued)

d. <u>Primary to Secondary LEAKAGE through Any One SG</u>

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. 7). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

Calculations for primary-to-secondary leakage are performed using approximate Standard Reference State of 25°C. When determining primary-to-secondary leakage of 150 gallons per day, indeterminant inaccuracies associated with determination of leakage are not considered.

For MODES 3 and 4, the primary system radioactivity level (source term) may be very low, making it difficult to measure primary-to-secondary leakage of 150 gallons per day. Therefore, if steam generator water samples indicate less than the minimum detectable activity of $5.0{*}E^{-7}$ microcuries/ml for each principal gamma emitter, the leakage requirement of Specification 3.4.13.d may be considered met.

(continued)

BASES (continued)

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.

A note has been added to the APPLICABILITY. For MODES 3 and 4, the primary system radioactivity level (source term) may be very low, making it difficult to measure primary-to-secondary leakage of 150 gallons per day. Therefore, if steam generator water samples indicate less than the minimum detectable activity of $5.0*E^{-7}$ microcuries/ml for each principal gamma emitter, the leakage requirement of Specification 3.4.13.d. may be considered met.

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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If any pressure boundary LEAKAGE exists, or primary to secondary LEAKAGE is not within limit, or if unidentified or identified LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 4, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 9). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 9, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

(continued)

BASES

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 level, makeup and letdown, and RCP seal injection and return flows). The Surveillance is modifid 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 (Tavg changes less than 5°F per hour) power level, pressurizer and makeup tank levels, makeup and letdown (balanced with no diversion to LHUTS), and RCP seal injection and return flows.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and by the containment structure sump level and flow monitoring system. It should be noted that LEAKAGE past seals, gaskets or CRDM canopy seal welds 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. The 12 hour Frequency after steady state operation has been achieved provides for those situations following a transient such that the 72 hours plus extension allowed by SR 3.0.2 would be exceeded. Under these circumstances, the SR would be due within 12 hours after steady state operation has been reestablished.

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 3.4.17, “Steam Generator Tube Integrity,” should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 8. 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. 8).

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 4, 1987 and GDC 16, 1967.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Chapter 15.
4. UFSAR, Chapter 3.
5. NUREG-1061, Volume 3, November, 1984.
6. 10 CFR 50.67.
7. NEI 97-06, “Steam Generator Program Guidelines.”
8. EPRI, “Pressurized Water Reactor Primary-to-Secondary Leak Guidelines.”
9. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55, 1971 of 10 CFR 50, Appendix A (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. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through two series valves is determined by a water inventory balance (SR 3.4.13.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leak tight.

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. Exceeding the leakage limit may indicate the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for low pressure injection.

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

(continued)

BASES

BACKGROUND (continued)

PIVs are provided to isolate the RCS from the following typically connected systems:

a. Residual Heat Removal (RHR) System;

b. Safety Injection System; and

c. Chemical and Volume Control System.

The PIVs are listed below:

VALVE NUMBER	FUNCTION
8948A, B, C, and D	Accumulator, RHR, and SIS first off check valves from RCS cold legs
8956A, B, C, and D	Accumulator second off check valves from RCS cold legs
8818A, B, C, and D	RHR second off check valves from RCS cold legs
8819A, B, C, and D	SIS second off check valves from RCS cold legs
8949A, B, C, and D	RHR and SIS first off check valves from RCS hot legs
8740A and B	RHR second off check valves from RCS hot legs
8905A, B, C, and D	SIS second off check valves from RCS hot legs
8701 and 8702	RHR suction isolation valves

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 RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is typically designed for 600 psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA. RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. Reference 7 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, valves in the RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR mode of operation. In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.
ACTIONS	The ACTIONS are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires entry into the applicable conditions and required actions for systems made inoperable by an inoperable PIV. The degraded condition that caused 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(s).

(continued)

BASES

ACTIONS (continued)

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

The flow path must be isolated by two valves. Required ACTIONS A.1, A.2.1, and A.2.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required ACTION A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4-hour Completion Time allows the actions and restricts operation with leaking isolation valves.

Required ACTIONS A.2.1 and A.2.2 require that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation or restoring the RCS PIV to within limits. The following isolation valve may be used to satisfy Technical Specification 3.4.14 Required Actions A.1 or A.2.1 when in Condition A for valves 8740A and 8740B.

VALVE NUMBER	FUNCTION
8703	RHR third off isolation valve to RCS hot legs

The 72 hour Completion Time after exceeding the limit allows for the restoration of the leaking PIV to OPERABLE status or use of a third off isolation valve. The 72 hour completion time after exceeding the limit considers the time required to complete the ACTION and the low probability of a second valve failing during this time period.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. This action may reduce the leakage and also reduces the potential for a LOCA outside containment.

(continued)

BASES

ACTIONS (continued)

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 10). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 10, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. This method results in testing each valve separately. 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.

Test pressures less than 2235 psig but greater than 150 psig are allowed for valves where higher pressures would tend to diminish leakage channel opening. Observed leakage shall be adjusted for actual pressure to 2235 psig assuming the leakage to be directly proportional to pressure differential to the one half power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

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. For check valves 8956A-D, evaluation determined that trickle forward flow of 10 gpm or less through these valves would not challenge their seating integrity and therefore do not require testing to ensure tight reseating (Reference 9).

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.

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

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

SR 3.4.14.2 and 3.4.14.3

Not Used

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, Section V, GDC 55, 1971.
4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.
5. NUREG-0677, May 1980.
6. Not Used
7. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2001 Edition including 2002 and 2003 Addenda.
8. 10 CFR 50.55a(g).
9. AR A0569744.
10. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 16, 1967 of Appendix A to 10 CFR 50 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

The containment sumps used to collect unidentified LEAKAGE and the containment fan cooling unit (CFCU) condensate collection monitors are capable of detecting increases above the normal flow rates.

Each CFCU has an individual condensate collection monitor. The condensate from the cooling coils passes out from the CFCU to a containment sump. The condensate collection system design does not use an on-line flow monitor. The condensate drain flow can be collected, measured, and then using the elapsed time of the collection, the average flow rate can be determined. This monitoring can be done from the control room. Although multiple CFCUs may be operating, any individual CFCU condensate monitor may be employed to provide indication of the condensate flow rate.

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. For this reason, in addition to meeting the OPERABILITY requirements, the gaseous and particulate containment atmosphere radioactivity monitor alarms are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

(continued)

BASES

BACKGROUND (continued)	Other indications may be used to detect an increase in unidentified LEAKAGE; however, they are not required to be OPERABLE by this LCO. Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements is affected by containment free volume and, for temperature, detector location. Alarm signals from temperature and pressure instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO. The above-mentioned LEAKAGE detection methods or systems differ in sensitivity and response time based on factors including leak location, RCS temperature, and RCS activity. Some of these systems could serve as early alarm systems signaling the operators that closer examination of other detection systems is necessary to determine the extent of any corrective action that may be required.
APPLICABLE SAFETY ANALYSES	The asymmetric loads produced by postulated breaks are the result of assumed pressure imbalance, both internal and external to the RCS. The internal asymmetric loads result from a rapid decompression that causes large transient pressure differentials across the core barrel and fuel assemblies. The external asymmetric loads result from the rapid depressurization of the annulus regions, such as the annulus between the reactor vessel and the shield wall, and cause large transient pressure differentials to act on the vessel. These differential pressure loads could damage RCS supports, core cooling equipment or core internals. This concern was first identified as Multiplant Action (MPA) D-10 and subsequently as Unresolved Safety Issue (USI) 2, "Asymmetric LOCA Loads" (Ref. 4). The resolution of USI-2 for Westinghouse PWRs was the use of fracture mechanics technology for RCS piping > 10 inches diameter. (Ref. 5). This technology became known as leak before-break (LBB). Included within the LBB methodology was the requirement to have leak detection systems capable of detecting a 1.0 gpm leak within four hours. This leakage rate is designed to ensure that adequate margins exist to detect leaks in a timely manner during normal operating conditions. The use of the LBB methodology is described in Reference 6. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 leak occur that could be detrimental to the safety of the unit and the public. RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of unidentified LEAKAGE are detected in time to allow actions to place the plant in a safe condition when RCS LEAKAGE indicates possible RCPB degradation. The LCO requires three instruments to be OPERABLE. OPERABILITY of the containment sump monitor systems, the particulate radioactivity monitor, the gaseous radioactivity monitor, and the CFCU condensate collection monitor is based on the capability to indicate a 1 gpm leak rate within four hours. This allowable response time is based on the LBB methodology criterion for leakage detection systems, for plants with leakage detection systems that did not meet all of the provisions of Regulatory Guide 1.45, that at least one leakage detection system with sensitivity capable of detecting an unidentified leakage rate of one gpm in four hours should be operable (References 5 and 7). The containment structure sumps and reactor cavity sump are used to collect unidentified LEAKAGE. The containment structure sumps and the reactor cavity sump have associated sump level and sump pump integrated flow monitors that are visually monitored to detect when there is an increase in LEAKAGE above the normal value. The identification of an increase in unidentified LEAKAGE will be delayed by the time required for the unidentified LEAKAGE to travel to the sumps 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.

(continued)

BASES

LCO (continued)

The reactor coolant contains radioactivity that, when released to the containment, may be detected by the gaseous or particulate containment atmosphere radioactivity monitor. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE, but have recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate containment atmosphere radioactivity monitors to detect a 1 gpm increase within four hours during normal operation. However, the gaseous or particulate containment atmosphere radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in unidentified LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 3).

An increase in humidity of the containment atmosphere could indicate the release of water vapor to the containment. The condensate drain flow from the CFCUs is collected and the average flow rate is manually determined using the elapsed time to collect a constant volume of condensate. Elapsed times less than a predefined value indicate a 1 gpm increase in unidentified LEAKAGE. The time required to detect a 1 gpm or more increase above the normal value varies based on environmental and system conditions and may take longer than 1 hour and up to 4 hours. This sensitivity is acceptable for CFCU condensate collection monitor OPERABILITY.

OPERABILITY of the RCS leakage detection instrumentation includes the control room indication associated with the instrumentation and control room alarms for the gaseous and particulate containment atmosphere radioactivity monitors.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor systems, the particulate radioactivity monitor and either a CFCU condensate collection monitor or a gaseous radioactivity monitor provides an acceptable minimum.

(continued)

BASES (continued)

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 any containment sump monitor inoperable, RCS water inventory balance, the containment atmosphere particulate radioactivity monitor, and the CFCU condensate collection monitoring system will provide indications of changes in leakage. Together with the containment atmosphere radioactivity monitors, 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 as defined in Bases of SR 3.4.13.1. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the sump monitoring system to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitoring system 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 the particulate containment atmosphere radioactivity monitor inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the containment atmosphere particulate radioactivity monitor.

(continued)

BASES

ACTIONS

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

The 24 hour interval provides periodic information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation defined in Bases of SR 3.4.13.1. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of LEAKAGE detection is available.

C.1.1, C.1.2, C.2.1, and C.2.2

With the required containment atmosphere gaseous radioactivity monitor and the required CFCU condensate collection monitor inoperable, the means of detecting leakage are the containment sump monitoring system and the containment atmosphere particulate radioactivity monitor. This Condition does not provide all the required diverse means of leakage detection. With both gaseous containment atmosphere radioactivity monitoring and CFCU condensate monitoring instrumentation channels inoperable, alternate 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.

The follow-up Required Action is to restore either of the inoperable required monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

(continued)

BASES

ACTIONS (continued)

D.1, D.2.1, D.2.2, and D.2.3

With any containment sump monitor, the containment atmosphere particulate radioactivity monitor, and the CFCU condensate collection monitor inoperable, the only means of detecting LEAKAGE is the containment gaseous radioactivity monitor. The containment atmosphere gaseous radioactivity monitor typically cannot detect a 1 gpm leak within four hours 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 and analyzed to provide alternate periodic information. The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

E.1

With all required monitors inoperable, (LCO a, b, and c) no means of monitoring leakage are available, and immediate plant shutdown to MODE 5, the first MODE that requirements of this LCO are not applicable, in accordance with LCO 3.0.3 is required.

F.1 and F.2

If a Required Action of Condition A, B, C, or D cannot be met, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 8). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 8, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES (continued)

ACTIONS (continued)

Required Action F.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitors. The check gives reasonable confidence that the channels are 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 CHANNEL FUNCTIONAL TEST (CFT) on the required containment atmosphere radioactivity monitors. The test ensures that the monitors can perform their function in the desired manner including alarm functions. 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, SR 3.4.15.4, and SR 3.4.15.5

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 Frequency of 24 months (except for the containment atmosphere particulate and gaseous radioactivity monitors which have a frequency of 18 months) is consistent with refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 16, 1967.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. UFSAR, Section 5.2.7.
4. NUREG-609, "Asymmetric Blowdown Loads on PWR Primary System," 1981.
5. Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Breaks in PWR Primary Main Loops."
6. UFSAR, Appendix 3.6B.
7. NUREG-1061, Volume 3, “Report of the U.S. Nuclear Regulatory Commission Piping Review Committee,” 1984.
8. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

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 the control room operators must be limited per GDC 19, 1971. The limits on specific activity ensure that the 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 RG 1.183 (Ref. 2) and 10 CFR 50.67 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting offsite and control room doses meet the appropriate SRP acceptance criteria following a SLB or a 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 0.75 gpm. 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 analysis 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.

The analyses consider two cases of reactor coolant 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas specific activity is assumed to be 270 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 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 DOSE EQUIVALENT I-131, 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).
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 270.0 μCi/gm DOSE EQUIVALENT XE-133, as contained in SR 3.4.16.2 and SR 3.4.16.1 respectively. The limits on specific activity ensure that offsite and control room doses will meet the appropriate acceptance criteria (Refs. 1 and 2).

(continued)

BASES

LCO (continued)	The SLB and SGTR accident analysis (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	<u>A.1 and A.2</u> 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 $\leq$60.0 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend. The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is 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 3.0.4c. This allowance permits entry into the applicable MODE(S) while 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 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.

(continued)

BASES

ACTIONS (continued)

B.1

With the DOSE EQUIVALENT XE-133 in excess of the allowed limit, DOSE EQUIVALENT XE-133 must be restored to within limits 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 the use of the provisions of LCO 3.0.4c. 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 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.

C.1 and C.2

If the Required Action and the 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.

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.

If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 in Specification 1.1, "Definitions," is not detected, it should be assumed to be present at the minimum detectable activity.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

The definition of DOSE EQUIVALENT XE-133 in Specification 1.1, "Definitions," requires that the determination of DOSE EQUIVALENT XE-133 shall be performed using the effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12, 1993, “External Exposure to Radionuclides in Air, Water, and Soil.” These dose conversion factors are consistent with the dose conversion factors used in the applicable dose consequence analyses.

The Note modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

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 ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation; samples at other times would provide inaccurate results.

The definition of DOSE EQUIVALENT I-131 in Specification 1.1, "Definitions," specifies the dose conversion factors which may be used to determine DOSE EQUIVALENT I-131. The dose conversion factors used to determine DOSE EQUIVALENT I-131 are the committed thyroid dose conversion factors from Table 2.1 of EPA Federal Guidance Report No. 11, 1988, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion and Ingestion,” and are consistent with the dose conversion factors used in the applicable dose consequence analyses.

The Note modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

(continued)

BASES (continued)

REFERENCES	1.	10 CFR 50.67.
	2.	Regulatory Guide 1.183, July 2000.
	3.	UFSAR, Sections 15.4.3 and 15.5.20.
	4.	UFSAR Section 15.5.18.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, 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 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a primary to secondary LEAKAGE rate of 0.75 gpm from the intact SGs plus the leakage rate associated with a double-ended rupture of a single tube. The SGTR radiological dose analysis assumes loss of off-site power at the time of reactor trip with no subsequent condenser cooling available. The SG PORV for the SG that has sustained the tube rupture is assumed to fail open for 30 minutes, at which time the operator closes the block valve to the PORV. The SGTR radiological dose analysis assumes the contaminated secondary fluid is released briefly to the atmosphere from all the PORVs following reactor trip, is released from the ruptured SG PORV for 30 minutes, is released from the intact SG PORVs during the cooldown, and is released from all PORVs following cooldown until termination of the event. 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.) The steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 0.75 gpm under accident 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) and RG 1.183 (Ref. 7). Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
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.

(continued)

BASES

LCO (continued)

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 5.5.9, "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 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.

(continued)

BASES

LCO (continued)	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. 4) and Draft Regulatory Guide 1.121 (Ref. 5). The accident induced leakage performance criterion ensures (a) that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions, and (b) that the primary to secondary LEAKAGE will not exceed 1 gpm per SG (except for specific types of degradation at specific locations where the NRC has approved greater accident induced leakage) to ensure that the potential for induced leakage during severe accidents will be maintained at a level that will not increase risk. The accident analyses for events resulting in steam release to the atmosphere, other than SGTR assume that leakage does not exceed 0.75 gpm total under accident conditions. For conservatism, the SLB analysis assumes that the total 0.75 gpm tube leakage is assigned to the faulted steam generator. 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	Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4. RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

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 3.4.17.2. 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 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.

(continued)

BASES

ACTIONS (continued)

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 3.4.17.1

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 function of degradation morphology, nondestructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	In addition, Specification 5.5.9 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 5.5.9 until subsequent inspections support extending the inspection interval. <u>SR 3.4.17.2</u> 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 5.5.9 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.
REFERENCES	1. NEI 97-06, “Steam Generator Program Guidelines.” 2. 10 CFR 50 Appendix A, GDC 19, 1999. 3. 10 CFR 50.67. 4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB. 5. Draft Regulatory Guide 1.121, “Basis for Plugging Degraded Steam Generator Tubes,” August 1976. 6. EPRI, “Pressurized Water Reactor Steam Generator Examination Guidelines.” 7. Regulatory Guide 1.183, July 2000.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply borated water to replace inventory in the reactor vessel during the latter phase of blowdown to the beginning phase of reflood of a loss of coolant accident (LOCA). The ECCS injection mode following a large break LOCA consists of three phases: 1) blowdown, 2) refill, and 3) reflood.

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 LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and spill 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 ECCS water.

The refill phase is complete when the injection of ECCS water has filled the reactor vessel downcomer and the lower plenum of the reactor vessel, which is bounded by the bottom of the fuel rods.

The reflood phase follows the refill phase and continues until the reactor vessel has been filled to the extent that core temperature rise has been terminated.

The accumulators function in the later stage of blowdown to the beginning of reflood to fill the downcomer and lower plenum. The injection of the ECCS pumps aid during refill. Reflood and the following long term heat removal is accomplished by water pumped into the core by the ECCS pumps.

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 an open motor operated isolation valve

(continued)

BASES

BACKGROUND (continued)	(8808A, B, C, and D) and by two check valves in series. The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.
APPLICABLE SAFETY ANALYSES	The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 1 and 3). 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 with no credit taken for ECCS pump flow until an effective delay has elapsed. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break. No operator action is assumed during the blowdown stage of a large break LOCA. The limiting large break LOCA is a double ended guillotine break in the RCS piping. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure. 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 SI pumps begin RCS injection, however, the increase in fuel clad temperature is terminated primarily by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and the ECCS centrifugal charging and SI pumps play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The accumulators do not discharge above the pressure of their nitrogen cover gas (579 to 664 psig.) At higher pressures the ECCS centrifugal charging pumps and SI pumps injection becomes 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) that are applicable for the accumulators will be met following a LOCA:

a. Maximum fuel element cladding temperature is $\leq$ 2200°F;
b. Maximum cladding oxidation is $\leq$ 0.17 times the total cladding thickness before oxidation;
c. Maximum hydrogen generation from a zirconium-water reaction is $\leq$ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding cladding surrounding the plenum volume, were to react; and
d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown and reflood phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46, though their water volume is credited as part of the long term cooling inventory.

For both the large and small break LOCA analyses, a contained accumulator water volume (814 cubic feet to 886 cubic feet) is used. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged. In the NRC-approved methodology used to analyze large breaks, an increase in water volume may result in 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 analysis credits the nominal line water volume from the accumulator to the check valve. The safety analysis assumes values of $\geq$814 cubic feet and $\leq$886 cubic feet. The uncertainty values used in the LOCA analyses bound instrument uncertainty.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	A reduction below the accumulator LCO minimum boron concentration would produce a subsequent reduction in the available containment recirculation sump boron concentration for post LOCA shutdown and an increase in the 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 large and small break LOCA analyses use a nitrogen cover pressure range (579 psig to 664 psig). The maximum nitrogen cover pressure limit (664 psig) provides margin to assure inadvertent relief valve actuation does not occur. These analysis-assumed pressures are specified in the SRs. Volumes are shown on the control board indicators as % readings on accumulator narrow range level instruments. Adjustments to the analysis parameters for instrument inaccuracies or other reasons are applied to determine the acceptance criteria used in the plant surveillance procedures. These adjustments assure the assumed analyses parameters are maintained. The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 1 and 3). The accumulators satisfy Criterion 2 and 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. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated. For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above a nominal pressure of 1000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

(continued)

BASES (continued)

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 RCS pressures > 1000 psig. At pressures $\leq$ 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 $\leq$ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are normally 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. Accumulator may be unisolated when accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR. This condition is in agreement with the TS 3.4.12 LCO requirement.
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, the ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analyses demonstrate that the accumulators will discharge following a large main steam line break. The impact of their discharge is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits. <u>B.1</u> If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hour Completion Time to open the valve, remove

(continued)

BASES

ACTIONS

B.1 (continued)

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 potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049-A, Rev 1. (Ref. 7)

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and RCS pressure reduced to $\leq$ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator motor operated isolation valve (8808A, B, C, and D) 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.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	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 solution volume increase of 5.6% (101 gallon) narrow range indicated level will identify whether in-leakage 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), and the RWST has not been diluted since verifying that its boron concentration satisfies SR 3.5.4.3, because the water contained in the RWST is nominally within the accumulator boron concentration requirements as verified by SR 3.5.4.3. This is consistent with the recommendation of GL 93-05 (Ref. 4). SR 3.5.1.5 Verification that power is removed from each accumulator isolation valve operator (8808A, B, C, and D) when the RCS pressure is greater than 1000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure 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 less than or equal to 1000 psig, thus allowing the valves to be closed to enable plant shutdown without discharging the accumulators into the RCS.
REFERENCES	1. UFSAR, Chapter 6. 2. 10 CFR 50.46. 3. UFSAR, Chapter 15. 4. GL 93-05, Item 7.1. 5. DCM S-38A. 6. License Amendment 147/147, May 3, 2001. 7. WCAP-15049-A, Rev 1, April, 1999.

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), non-isolable coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

The ECCS consists of three separate subsystems: centrifugal charging (high head), safety injection (SI) (intermediate head), and residual heat removal (RHR) (low head). Each subsystem consists of two redundant, 100% capacity trains. The ECCS accumulators and the Refueling Water Storage Tank (RWST) are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS components are divided into two trains, A and B. The following are the train assignments for the ECCS pumps.

Train A:	Train B:
RHR Pump 2	RHR Pump 1
SI Pump 1	SI Pump 2
Centrifugal Charging Pump (CCP) 1	Centrifugal Charging Pump (CCP) 2

The ECCS flow paths consist of piping, valves, heat exchangers, 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 CCPs, the RHR pumps, heat exchangers, and the SI pumps.

Each of the three 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.

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BASES

BACKGROUND (continued)

The containment recirculation sump consists of a front strainer section anchored at El, 91' and a second rear strainer section at El 88'. Each of the strainer sections is made up of a series of plenums which are connected together to form a central supply chamber and connected at the entry to each of the two 14" RHR pump suction lines through interconnecting chambers. Into these plenums are installed disks which comprise the actual strainer surfaces. The entire strainer system is designed to filter out any material greater than 3/32" in diameter. The trash rack extends around the sides and top portion of the strainer located outside the sump to protect the strainer sections from damage due to traffic during outages.

There are three phases of ECCS operation following a LOCA: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the 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 recirculation sump has enough water to supply the required net positive suction head to the RHR pumps, suction is switched to the containment recirculation sump for cold leg recirculation. After several hours, the ECCS operation is shifted to the hot leg recirculation phase to provide reverse flow through the core to backflush out the high boron concentration that could result from core boiling after a cold leg break.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. The RWST header supplies separate piping for each subsystem. The discharge from the CCPs combines in a common header and then divides again into four supply lines, each of which feeds the injection line to one RCS cold leg. The discharge from the SI and RHR pumps divides and feeds an injection line to each of the RCS cold legs. Throttle/runout valves are set to balance the flow to the RCS. The throttle/runout valves also protect the SI and CCPs from exceeding their runout flow limits. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the CCPs supply water until the RCS pressure decreases below the SI pump shutoff head. During this period, the steam generators are used to provide part of the core cooling function.

(continued)

BASES

BACKGROUND (continued)

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment recirculation sump. The RHR pumps then supply the other ECCS pumps. Initially, recirculation discharge is through the same paths as the injection phase to the cold legs. Subsequently, recirculation provides injection to both the hot and cold legs.

The centrifugal charging subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of ECCS pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

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 after a one second sequencer delay in the programmed time 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, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

Each ECCS pump is provided with normally open miniflow lines for pump protection. The RHR miniflow isolation valves close on flow to the RCS and have a time delay to prevent them from closing until the RHR pumps are up to speed and capable of delivering fluid to the RCS. The SI pump miniflow isolation valves are closed manually from the control room prior to transfer from injection to recirculation. The CCP miniflow isolation valves are also closed manually from the control room prior to transfer from injection to recirculation.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

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BASES (continued)

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 $\leq$ 2200°F; b. Maximum cladding oxidation is $\leq$ 0.17 times the total cladding thickness before oxidation; c. Maximum hydrogen generation from a zirconium water reaction is $\leq$ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; d. Core is maintained in a coolable geometry; and e. Adequate long term core cooling capability is maintained. The LCO also limits the potential for a post-trip return to power following an MSLB event and ensures that containment temperature limits are met.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement to limit runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The centrifugal charging pumps and SI pumps are credited in the injection phase for mitigation of a small break LOCA event. This event establishes the flow and discharge head for the design point of the CCPs. The SGTR and MSLB events also credit the CCPs. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with or without loss of offsite power and a single failure disabling one ECCS train (all 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 ECCS train.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large break LOCA. It also ensures that the centrifugal charging and SI pumps will deliver sufficient water and boron during a small break LOCA to maintain core subcriticality. For smaller break LOCAs, the centrifugal charging 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).

(continued)

BASES (continued)

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 a centrifugal charging subsystem, an SI subsystem, and an RHR 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. 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 four cold legs. The ECCS suction is manually transferred to the containment recirculation sump to place the system in the recirculation mode of operation to supply its flow to the RCS hot and cold legs. During the recirculation operation, the RHR pumps provide suction to the charging and SI pumps. Management of gas voids is important to ECCS OPERABILITY.

The containment recirculation sump is considered OPERABLE when all the following conditions are met:

- All strainer disks are bolted in or blanks are installed.
- No structural distress that could impair strainer/trash rack function.
- Covers to all 13 access ports to the strainer system are installed.
- The two expansion joints connecting the rear strainer plenums to the pipe structure are intact.
- Lower plenum drain valve (SI-1-294 for Unit 1 or SI-2-295 for Unit 2) is closed, or the pipe cap or inlet strainer (STR-440) is installed.

During recirculation operation, the flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

(continued)

BASES (continued)

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. The centrifugal charging pump performance is based on a small break LOCA, which establishes the pump performance curve and has less dependence on power. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis. This LCO is only applicable in MODE 3 and above. Below MODE 3, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS—Shutdown." As indicated in the Note, the flow path may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "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."

(continued)

BASES (continued)

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 (capable of injection into the RCS, if actuated), the inoperable components must be returned to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their safety 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 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. The intent of this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available. (i.e. minimum of one OPERABLE CCP, SI, and RHR pump and applicable flow paths capable of drawing from the RWST and injecting into the RCS cold legs). This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

The intent of this Condition, to maintain a combination of equipment such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available, applies to both the injection mode and the recirculation mode.

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.

Reference 6 describes situations in which one component, such as an RHR cross-tie valve can disable both ECCS trains. With one or more component(s) inoperable such that 100% of the flow equivalent to a

(continued)

BASES

ACTIONS

A.1 (continued)

single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

Opening the containment recirculation sump strainer system access ports, or lower plenum drain valve (SI-1-294 for Unit 1 or SI-2-295 for Unit 2) without pipe cap or inlet strainer (STR-440) installed in MODES 1 through 3 is considered to be a condition which is outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

(continued)

BASES

ACTIONS

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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. Valve position is the concern and not indicated position in the control room. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of power ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. The surveillance can be satisfied using indicated position in the control room but may also be satisfied using local observation. These valves are of the type, described in References 6 and 7, 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. As noted in LCO Note 1, both SI pump flow paths may each be isolated for two hours in MODE 3 by closure of one or more of these valves to perform pressure isolation valve testing.

In addition to the valves listed in SR 3.5.2.1, there are other ECCS related valves that must be appropriately positioned. Improper valve position can affect the ECCS performance required to meet the analysis assumptions. These valves are identified in plant documents and are listed in the following table.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

ECCS Valve Position Table

Valve Number	Valve Function Valve Position	Required	MODES
8105	CCP 1 and 2 Recirc Line Isolation	Open	1, 2, 3
8106	CCP 1 and 2 Recirc Line Isolation	Open	1, 2, 3
8716A	RHR Cross-tie Line	Open	1, 2, 3
8716B	RHR Cross-tie Line	Open	1, 2, 3
9003A	RHR to Containment Spray	Closed	1, 2, 3
9003B	RHR to Containment Spray	Closed	1, 2, 3
8804A	RHR to CCP Closed	1, 2, 3	
8804B**	RHR to SI Pump	Closed	1, 2, 3
8741	RHR to RWST - Manual Valve	Closed	1, 2, 3
SI-1	RWST to ECCS - Manual Valve	Open	1, 2, 3, 4
8923A*	Train "A" SI Pump Suction Valve	Open	1, 2, 3

* Valve can be closed, but not when RHR Train "A" (containing RHR pump 2) is out of service. Closing this valve with RHR Train "A" out of service would result in both trains of ECCS being inoperable due to the ECCS piping configuration.

** 8804B may be opened, using administrative controls approved by PSRC, without entering TS 3.0.3, provided opening 8804B affects the OPERABILITY of only one ECCS subsystem.

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. The ECCS flow paths consist of the direct flow paths from the fluid source (e.g., RWST, accumulator) to the supplied PG&E Design Class I component (e.g., reactor vessel, pump) and portions of any branch line flow path off a direct flow path that a valve misposition could result in degradation of the system safety function. 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. This SR also does not apply to valves which are closed and secured by a cap or blind flange (e.g., manual test, vent, and drain valves), to valves that cannot be inadvertently misaligned (e.g., check valves), or to valves in instrument or sample lines. A valve that receives an actuation signal is allowed to be in a non-accident 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2 (continued)

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

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

SR 3.5.2.3

ECCS piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS and may also prevent water hammer, pump cavitation, gas binding, and pumping of non-condensable gas into the reactor vessel.

Selection of ECCS locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.3 (continued)

Program. If it is determined by subsequent evaluation that the ECCS is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

The intent of the SR is to assure the ECCS piping is adequately vented. Different means of verification, as alternates to venting the accessible system high points, can be employed to provide this assurance, such as ultrasonic testing the vent lines of the ECCS pump casings and accessible high point vents.

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. (Ref. 8) This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is within the performance assumed in the plant safety analysis. SRs are specified in the applicable portions of the Inservice Testing Program, which encompasses Subsection ISTB of the ASME

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4 (continued)

Code for Operation and Maintenance of Nuclear Power Plants. (Ref. 8). This section of the ASME Code provides the activities and frequencies necessary to satisfy the requirements.

The following ECCS pumps are required to develop the indicated differential pressure when tested on recirculation flow:

CCP ≥ 2400 psid

SI pump ≥ 1455 psid

RHR pump ≥ 165 psid

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 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. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.7

The correct position of throttle/runout valves in the ECCS flow paths is necessary for proper ECCS performance. These manual throttle/runout valves are positioned during flow balancing and have mechanical locks and seals to ensure that the proper positioning for restricted flow to a ruptured cold leg is maintained. The verification of proper position of a throttle/runout valve can be accomplished by confirming the seals have not been altered since the last performance of the flow balance test. Restricting the flow to a ruptured cold leg ensures that the other cold legs receive at least the required minimum flow. 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 recirculation sump suction inlet ensure that it is unrestricted and stays 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.

Opening the containment recirculation sump strainer system access ports, or lower plenum drain valve (SI-1-294 for Unit 1 or SI-2-295 for Unit 2) without pipe cap or inlet strainer (STR-440) installed in MODES 1 through 4 is considered to be a condition which is outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. UFSAR, Sections 6.3 and 7.3
4. UFSAR, Chapter 15, "Accident Analysis."
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. IE Information Notice No. 87-01.
7. BTP EICSB-18, Application of the Single Failure Criteria to Manually-Controlled Electrically-Operated Valves.
8. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2004 Edition including 2005 and 2006 Addenda
9. Design Changes DCP C-49857 (Unit 1), DCP C-50857 (Unit 2).
10. License Amendment 202/203, December 31, 2008
11. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, "Generic Letter 2008-01, Managing Gas Accumulation," Using the Consolidated Line Item Improvement Process.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND	In MODE 4, the ECCS is available to be manually started to provide water and negative reactivity to the reactor core, if needed. The required ECCS train consists of two separate subsystems: centrifugal charging (high head) and residual heat removal (RHR) (low head). The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) can be injected into the Reactor Coolant System (RCS) and subsequently transferring RHR pump suction to the containment recirculation sump. The 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.
APPLICABLE SAFETY ANALYSES	Based on the stable reactivity conditions and reduced core cooling requirements while in the Applicability, sufficient time exists for manual actuation of the required ECCS if needed, and automatic initiation is not required (Reference 1). Only one train of ECCS is required. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS -Shutdown satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

In MODE 4, one ECCS train is required to be OPERABLE to ensure that ECCS flow is available to the core, if needed.

In MODE 4, an ECCS train consists of a centrifugal charging subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment recirculation sump.

The containment recirculation sump is considered OPERABLE when all the following conditions are met:

- All strainer disks are bolted in or blanks are installed.
- No structural distress that could impair strainer/trash rack function.
- Covers to all 13 access ports to the strainer system are installed.
- The two expansion joints connecting the rear strainer plenums to the pipe structure are intact.
- Lower plenum drain valve (SI-1-294 for Unit 1 or SI-2-295 for Unit 2) is closed, or the pipe cap or inlet strainer (STR-440) is installed.

If ECCS actuation is needed, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS charging and RHR pumps and their respective supply headers to each of the four cold legs. In the long term, this flow path may be switched to take its supply from the containment recirculation sump and to deliver its flow to the RCS hot and cold legs. Management of gas voids is important to ECCS OPERABILITY.

This LCO is modified by a Note that allows an RHR train to be considered OPERABLE during system alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and is not otherwise inoperable. This allows operation in the RHR mode during MODE 4.

(continued)

BASES (continued)

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 high head and low head train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

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 Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS Centrifugal Charging Pump subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS Centrifugal Charging Pump subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to an event or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

(continued)

BASES

ACTIONS

A.1 (continued)

With the required RHR pump and heat exchanger inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

In MODE 4, opening the containment recirculation sump strainer system access ports, or lower plenum drain valve (SI-1-294 for Unit 1 or SI-2-295 for Unit 2) without pipe cap or inlet strainer (STR-440) installed, is considered to be a condition which makes the containment recirculation sump inoperable. Therefore, LCO 3.0.3 must be immediately entered.

With no ECCS centrifugal charging subsystem OPERABLE, due to the inoperability of the centrifugal charging pump or flow path from the RWST, the plant is not prepared to provide high pressure injection, if needed. The Completion Time of immediately to initiate actions that would restore at least one ECCS centrifugal charging subsystem to OPERABLE status ensures that prompt action is taken to provide the cooling capacity.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action A.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.5.3.1</u> The applicable Surveillance descriptions from Bases 3.5.2 apply.
REFERENCES	1. TSTF-575-T, Revise TS 3.5.3, ECCS Shutdown, Bases, Revision 0, March 2019. 2. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010. 3. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, “Generic Letter 2008-01, Managing Gas Accumulation,” Using the Consolidated Line Item Improvement Process.

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 (boration flow path), to the refueling cavity during refueling, and to the ECCS and the Containment Spray (CS) System during accident conditions.

The RWST supplies both trains of the ECCS through one header and both trains of the CS System through a separate supply header during the injection phase of a loss of coolant (LOCA) recovery. Motor-operated isolation valves in each sub-system header isolate the RWST from the ECCS and from the CS System once the RWST is no longer supplying flow to these systems.

Use of a single RWST to supply both trains of the ECCS and CS Systems is acceptable since the RWST is a passive component, and a passive failure is not assumed to occur coincidentally with a Design Basis Accident (DBA).

During normal plant operation in MODES 1, 2, and 3, the Safety Injection (SI) and Residual Heat Removal (RHR) pumps are aligned to take suction from the RWST. The Centrifugal Charging Pumps (CCPs) operate during normal plant operation with their suction aligned to the Volume Control Tank (VCT). The switchover from normal operation to the injection phase of ECCS operation requires auto-transfer of the CCP suction from the CVCS VCT to the RWST. The CS pumps suction is aligned to the RWST with closed motor operated discharge valves which open on a CS signal.

When the suction for the RHR pumps is transferred to the containment recirculation sump, the RWST must be isolated from ECCS and CS system. The isolation prevents flow of containment recirculation sump water into the RWST. Flow of containment water into the RWST could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the RHR pumps due to loss of containment recirculation sump inventory.

The reactivity control systems are available to the operators to ensure that negative reactivity is available during each mode of plant operation. This system is not an automatic accident mitigation system, but is used under operator control if needed to increase the Reactor Coolant System (RCS) boration concentration. The sources of borated water are the boric acid storage tanks in the CVCS and the RWST. The RWST source of borated water is available as an alternate source

(continued)

BASES

BACKGROUND (continued)	to the boric acid storage tanks. RWST water can be used in the event of abnormal conditions, including single active failure events that may impair the function of the boric acid storage tank source of borated water of the CVCS. The boration subsystem provides the means to meet one of the functional requirements of the CVCS, i.e., to control the neutron absorber (boron) concentration in the RCS and to help maintain the SHUTDOWN MARGIN (SDM). The LCO ensures that: a. The RWST contains a sufficient volume at an acceptable boron concentration and temperature to support the ECCS and CS systems during the injection phase; b. Sufficient water volume exists in the containment recirculation sump to support continued operation of the ECCS System pumps at the time of transfer to the recirculation mode of cooling. The sump strainers are required to be fully submerged to prevent vortexing and air ingestion, during changeover from the injection mode to the recirculation mode for a large-break LOCA (LBLOCA) (Reference 7) c. The reactor remains subcritical following a LOCA.
APPLICABLE SAFETY ANALYSES	During accident conditions, the RWST provides a source of borated water to the ECCS and CS System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS-Operating"; B 3.5.3, "ECCS-Shutdown"; and B 3.6.6, "Containment Spray and Cooling Systems." 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. Any event that results in SI initiation, including inadvertent ECCS actuation, results in delivery of RWST water to the RCS. However, the events for which the RWST parameters provide mitigation or are limiting are large and small break LOCAs and steam line break. Feedwater line break and steam generator tube rupture (SGTR) also involve SI but the RWST parameters are less significant to the analysis results. RWST boron concentration is an explicit assumption in the inadvertent ECCS actuation analysis, although it is typically a non-limiting event and the results are very insensitive to boron concentrations. The effect of these RWST parameters on LOCAs, main steam line break, feedwater line break, and SGTR are discussed below:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LOCA

Volume

Insufficient water in the RWST could result in insufficient borated water inventory in the containment recirculation sump when the transfer to the recirculation phase occurs. The deliverable volume limit is set by the LBLOCA and containment analyses. The RWST minimum contained water volume of 455,300 gallons (93.6% level uncorrected for instrument uncertainty) is required to fully submerge the sump strainer at the initiation of recirculation mode for a LBLOCA. The sump strainer does not need to be fully submerged during a SBLOCA (Reference 7).

For the RWST, the deliverable volume is less than the total volume contained since, due to the design of the tank, the ECCS suction nozzle elevation is above the bottom of the tank, so more water can be contained than can be delivered. The contained water volume limit includes an allowance for water not usable because of tank discharge location or other physical characteristics. The accident analysis minimum RWST low level volume of 250,000 gallons is used in the LOCA analyses to calculate a conservative switchover to sump recirculation time.

Boration

During accident conditions, the RWST provides a source of borated water to the ECCS and CS System pumps. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following a LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment. The minimum boron concentration limit ensures that the spray and the containment recirculation sump solutions, after mixing with the sodium hydroxide from the spray additive tank, will not exceed the maximum pH values. The maximum boron concentration limit ensures that the containment recirculation sump solution will not be less than the minimum pH requirement. The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Diablo Canyon UFSAR. 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.

For a large-break LOCA analysis, the RWST minimum contained water volume of 455,300 gallons (93.6% level uncorrected for uncertainty), and the lower boron concentration limit of 2300 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 2500 ppm is used to determine the maximum allowable time to initiate hot leg recirculation following a LOCA. The purpose of initiating hot leg recirculation is to avoid boron precipitation in the core following the accident when the break is in the cold leg.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Boration (continued)

For the containment response following a MSLB, the lower limit on boron concentration is used to maximize the total energy release to containment.

At the time hot leg switchover is performed, there is the potential following a cold leg LOCA that boron-diluted liquid from the containment sump will displace the boron-concentrated liquid in the core. To compensate for this momentary reduction of boron in the core, control rod insertion and the boron equivalent worth of Xenon at hot leg switch over (HLSO) have been credited after a cold leg LOCA to provide negative reactivity necessary to assure core subcriticality.

Temperature

The primary reason for the TS minimum RWST temperature is to ensure the water will be above freezing. In addition,

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Temperature (continued)

a low RWST temperature will reduce the containment back pressure during the large-break LOCA transient.

The use of minimum containment backpressure in the LOCA analysis results in a conservative calculation of Peak Clad Temperature (PCT). The basis for this conclusion is the effect that the containment pressure has on the core reflood rate. A lower containment pressure has the effect of reducing the density of the steam exiting the break, which increases the differential pressure provided by the downcomer head (this phenomena is sometimes referred to as steam binding). Thus, a higher downcomer mixture level is required to maintain the same reflood rate as before. The additional time required to establish the downcomer head translates into a reduction in the reflood rate in the core. When the downcomer has completely filled, the equilibrium reflood rate for the low containment pressure case would be less than that calculated for a high containment pressure case. This reduction in reflood rate results in a reduction in heat transfer and ultimately an increase in the calculated PCT. Thus, the regulations require that a low containment pressure be calculated in the large-break LOCA analysis.

The LOCA analysis models the containment spray temperature within the range of 46°F to 90°F, based on historical plant data. However, the safety injection flow spilled into containment is modeled at the minimum RWST temperature limit of 35°F.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Steam Line and Feedwater Line Breaks

Volume

RWST volume is not an explicit assumption in other than LOCA events since the required volume for those events is much less than that required by LOCA.

Boration

The minimum RWST solution boron concentration is an explicit assumption in the MSLB analysis to ensure the required shutdown capability. Since DCPP no longer uses the boron injection tank, the minimum boron concentration limit is an important assumption in ensuring the required shutdown capability. For the containment response following an MSLB, the lower limit on boron concentration is used to maximize the total energy release to containment.

Feedwater line break results in high temperature/high pressure in the RCS. There is very little RWST water injected due to the high pressure. Also, the analysis results are not affected by the negative reactivity provided by RWST water. Therefore, RWST boron concentration is not a consideration for the feedwater line break.

Temperature

Minimum temperature is assumed in the MSLB core response analysis. Assuming minimum temperature for the MSLB is conservative as a MSLB causes substantial RCS cooling due to uncontrolled steam release and increases core reactivity. Cold water adds positive reactivity, however, this effect is covered by the negative reactivity provided by the boron in the RWST water.

Minimum RWST temperature is not assumed for the feedwater line break, since warmer RWST temperatures are more limiting. However, since RCS pressure remains high during this event, there is very little RWST water injected and the temperature does not have a significant effect.

Steam Generator Tube Rupture (SGTR)

Volume

The RWST volume needed in response to a SGTR is not an explicit assumption since the required volume is much less than that required by a LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Boration Borated RWST water will be injected into the RCS for a SGTR event. The insertion of the control rods and the negative reactivity provided by the injected RWST solution provides sufficient SDM during the initial recovery operations. One of the initial operator recovery actions for this event is to equalize the RCS pressure and the faulted steam generator pressure to minimize or stop the primary-to-secondary tube rupture flow and terminate safety injection. Further RCS boration will be initiated by the operator by manual makeup to the RCS. The RWST satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii). Temperature Minimum RWST water temperature is not a factor in SGTR. The heat capacity of RWST water injected into the RCS is small relative to the RCS inventory and heat sources.
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 recirculation sump to support ECCS 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 CS System OPERABILITY requirements. Since both the ECCS and the CS 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."

(continued)

BASES (continued)

ACTIONS

A.1

With RWST boron concentration or borated water temperature* not within limits, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the CS 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.

DCPP does not have an upper limit for RWST borated water temperature. An upper limit would typically be about 100°F. The coastal weather at the DCPP site is moderated by the Pacific Ocean and historically does not exceed 100°F. A requirement for a high temperature limit would therefore not be of value.

* The requirement for RWST temperature is to be greater than or equal to the minimum required temperature. The expression "within the required limits," applied to RWST temperature is satisfied when the temperature is greater than or equal to the minimum.

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 CS System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains and that borated water volume can be restored more rapidly than boron concentration or temperature.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 8). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 8, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified to be above the minimum assumed in 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.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperature is above the minimum temperature for the RWST. With ambient air temperature above the minimum temperature, the RWST temperature should not exceed the limit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	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 ECCS injection and CS System pump operation and to support continued ECCS on recirculation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. To ensure the minimum contained borated water volume of 455,300 gallons (equivalent to 93.6% RWST level uncorrected for uncertainty) is met, the RWST level shall be maintained ≥ 94.25% using the local digital indicator on LT-920, LT-921, or LT-922 (lowest reading). 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. 2. Surveillance Test Procedure C-20, "Boric Acid Inventory." 3. Calc STA-255, "Minimum Required RWST Level for GE Sump Strainers." 4. Calc N-227, "Post-LOCA Minimum Containment Sump Level." 5. Calc J-153, "RWST Level Using Temporary Gauge." 6. Calc J-143A, "RWST Level Instrument Channels with 3051N Transmittors." 7. License Amendment 199/200, "Issuance of Amendments Re: Technical Specification 3.5.4, "Refueling Water Storage Tank (RWST)." 8. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

This LCO is applicable because the centrifugal charging pumps (CCPs) are utilized for High Head Safety Injection (SI) while at the same time supplying flow to the reactor coolant pump (RCP) seals. The intent of the LCO is to ensure that the seal injection flow resistance remains within limit. This in turn will assure that flow through the RCP seal injection line during an accident is restricted. The seal injection flow is restricted by the injection line hydraulic flow resistance which is adjusted through positioning of the manual seal injection throttle valves.

The hydraulic resistance limits the amount of emergency core cooling system (ECCS) flow that would be diverted from the injection path to the reactor coolant system (RCS) into the RCP seal injection line. This limit supports safety analyses assumptions that are required because the RCP seal injection is not isolated by a SI signal and RCP seal injection is not credited for core cooling.

The flow resistance is determined by measuring the pressurizer pressure, the CCP discharge header pressure, and the RCP seal injection flow rate. If it is necessary to change the RCP seal injection line hydraulic flow resistance, the position of the injection throttle valves is adjusted to provide the desired resistance value.

The charging flow control valve FCV-128 throttles the centrifugal charging pump discharge flow as necessary to maintain the programmed level in the pressurizer. The flow control valve fails open to ensure that, in the event of either loss of air or loss of control signal to the valve, when the CCPs are supplying charging flow, seal injection flow to the RCP seals is maintained. Positioning of the charging flow control valve may vary during normal plant operating conditions, resulting in a proportional change to RCP seal injection flow. The hydraulic resistance of the RCP seal injection throttle valves will remain fixed when FCV-128 is repositioned provided the throttle valve(s) position are not adjusted. To avoid plant perturbation, the charging flow control valve may be positioned in a manner which is required to support periodic surveillance and normal plant operation.

(continued)

BASES

BACKGROUND (continued)

The accident analysis model assumes CCP header pressure is measured at the discharge of the CCP, upstream of the charging flow control valve. The flow control valve, which provides a modulating flow restriction to maintain pressurizer level during operation, is assumed to fail open during an accident. Any system resistance provided by the flow control valve during normal operation would result in non-conservative throttle valve settings if the CCP header pressure was measured at the discharge of the CCP upstream of the flow control valve. To avoid this problem, the CCP discharge header pressure is measured downstream of the flow control valve. This conservative measurement location also avoids the need to place the flow control valve in a full open test position during operation, thus avoiding perturbations in pressurizer water level.

Seal injection flow to the RCP seals is maintained during the injection phase of an SI following the occurrence of a design accident. The ECCS analyses provide no core cooling credit for that portion of the safety injection flow that enters the RCP through the seal injection flow path under minimum safeguards conditions. The limitation on seal injection flow ensures that in the event of an accident, the safety injection flow will be controlled within the constraints assumed in the accident analyses. The ECCS model utilizes a hydraulic flow resistance for the RCP seal injection flow path to determine the seal flow rather than specifying an actual flow rate. The hydraulic flow resistance is established by positioning the manual seal injection throttle valves and does not change if the valves are not adjusted. The accident analyses assumptions (based on hydraulic resistance) are satisfied notwithstanding changes in charging flows even though the indicated RCP seal injection flow may exceed 40 gpm for plant operation.

The accident analysis model assumes that RCS pressure is referenced to the RCP balance chamber. The RCP balancing chamber is the area above the thermal barrier and around the radial bearing. The pressure within the RCP balancing chamber is in a location which is not instrumented. Therefore, to establish the proper RCP seal injection flow line resistance, the differential pressure across the manual seal injection throttle valves is measured using the pressurizer pressure corrected to the discharge of the RCP seal injection flow path at the RCP balancing chamber.

The limitation set on RCP seal injection line hydraulic flow resistance is verified at a nominal pressurizer pressure $\geq$ 2215 psig and $\leq$ 2255 psig. However, resistance flow can be measured and established within the ECCS safety analysis limit anytime there is a differential pressure between the charging header and the RCS. The surveillance will normally be performed at nominal pressurizer pressure which is considered the pressure required to support plant operation.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The LOCA analyses establish the minimum flow for the ECCS pumps while the inadvertent SI and the SGTR analyses establish the maximum flow for the ECCS pumps. The CCPs are also credited in the small break LOCA analysis. Maximum ECCS flow analyses credit the CCPs and are limiting in their requirements for RCP seal flow. Reference to the 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. The ECCS flow balance assumes a minimum resistance of 0.2117 ft/gpm^2 in the RCP seal injection path with the flow control valve fully open. This LCO ensures that seal injection flow resistance is OPERABLE. Seal injection flow will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the CCPs will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory. Seal injection flow satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The intent of the LCO limit on seal injection flow resistance is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the cold legs (Ref. 1). This is accomplished by limiting the line resistance in the RCP seal injection lines to a value consistent with the assumptions in the accident analysis. The limit on RCP seal injection line hydraulic flow resistance must be met to assure that the ECCS is OPERABLE. If this limit is not met, the ECCS flow may not be as assumed in the accident analyses. The restriction on seal injection flow is accomplished by maintaining the seal water injection hydraulic resistance greater than or equal to 0.2117 ft/gpm^2. With the flow resistance within limits, the resulting total seal injection flow will be within the assumption made for seal flow during accident conditions.

(continued)

BASES

LCO (continued)	The seal injection flow hydraulic resistance is the parameter which is controlled to ensure that the ECCS alignment is maintained consistent with the accident analysis model. The seal injection flow is a result of the control of hydraulic resistance and is not controlled directly. During normal plant operation, it is possible for the indicated total seal flow to be greater than 40 gpm while still being within the LCO requirements for OPERABILITY because the resistance limit ensures RCP seal flow will be within analyses during ECCS operation. In order to establish the proper flow line resistance, the CCP discharge header pressure, the RCP seal injection flow rate, and the pressurizer pressure are measured. The line resistance is then determined from those inputs. A reduction in RCS pressure with no concurrent decrease in CCP discharge header pressure would increase the differential pressure across the manual throttle valves, and result in more flow being discharged through the RCP seal injection line. The flow resistance limit assures that when RCS pressure drops during a LOCA and seal injection flow increases in response to the higher differential pressure, the resulting flow will be consistent with 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 because high seal injection flow and the potential for reduced ECCS flow is less critical as a result of the lower initial RCS condition and decay heat removal requirements in MODE 4. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.
ACTIONS	<u>A.1</u> With the seal injection hydraulic flow resistance less than its limit, the amount of charging flow available for ECCS injection to the RCS may be reduced. Under this Condition, action must be taken to restore the seal injection flow resistance to within its limit. The operator has 4 hours from the time the seal injection hydraulic flow resistance is known to be below the limit to correctly position the manual valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is conservative with the Completion Times for other ECCS LCOs.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

When the Required Actions cannot be completed within the required Completion Time, a controlled shutdown must be initiated. The Completion Time of 6 hours for reaching MODE 3 from MODE 1 is a reasonable time for a controlled shutdown, based on operating experience and normal cooldown rates, and does not challenge plant safety systems or operators. Continuing the plant 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 hydraulic resistance within the limit ensures 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.

The seal water injection filters can affect the system flow. As differential pressure across the filter increases over the life of the filter element, certain operating adjustments may be made to maintain the RCP seal flow within the allowed limits. The effect on the system flow resulting from valving in a clean standby filter, after having adjusted the system over time, could result in a resistance flow value outside the TS limit. Therefore, instructions are provided that when a filter is removed from or returned to service, that the procedure to ensure flow characteristics of the seal injection water flow path satisfy the accident analysis and TS may need to be performed.

As noted, the Surveillance is to be completed within 4 hours after the RCS (pressurizer) pressure has stabilized within the specified pressure limits at nominal operating pressure. The RCS (pressurizer) 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.
2. 10 CFR 50.46.
3. License Amendment 148/148, May 7, 2001.

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. 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 with a reactor cavity pit projection, 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 exterior shell and concrete structure around the reactor vessel (crane wall and bio-shield wall) 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. The steel liner additionally provides support and anchorage for PG&E Design Class I piping and electrical raceway. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1), as modified by approved exemptions. The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

    1. capable of being closed by an OPERABLE automatic containment isolation system, or

    2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves"

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed and sealed; and

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS	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 loss of coolant accident (LOCA) and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or a fuel handling accident. 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 DBA 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 0.10% of containment air weight per day at P_a = 43.5 psig as defined in TS 5.5.16.b, which bounds the LOCA containment integrity safety analysis calculated results (Ref. 3). Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY. The containment satisfies Criterion 3 of 10CFR50.36(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. Compliance with this LCO will ensure a containment configuration, including equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Individual leakage rates specified for the containment air lock (LCO 3.6.2) and containment purge supply and exhaust, and containment pressure/vacuum relief valves with resilient seals (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, option B. 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.

(continued)

BASES (continued)

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 plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.6.1.1</u> Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements as specified in the Containment Leakage Rate Testing Program (Ref. 1). Failure to meet air lock and purge valve with resilient seal leakage limits specified in the 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 $< 0.6\ L_a$ 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 Containment Leakage Rate Testing Program. These periodic testing

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.1.1 (continued) requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis. SR 3.6.1.2 Not Used
REFERENCES	1. TS 5.5.16 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. There are two containment airlocks. The personnel air lock is nominally a right circular cylinder, approximately 9 ft in diameter, with a door at each end. The emergency air lock is approximately 5 ft inside diameter with a 2 ft 6 in door at each end. On both air locks, 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. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door). Each personnel air lock is provided with limit switches on both doors that provide control room indication of door position. 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 safety analyses.
APPLICABLE SAFETY ANALYSIS	In Mode 1, 2, 3, and 4, the DBA that results in a release of radioactive material within containment is a loss of coolant accident (Ref. 2). In the analysis of this accident, 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 peak calculated containment internal pressure for the design basis LOCA, P_a = 43.5 psig, as defined in TS 5.5.16.b, which bounds the LOCA containment integrity safety analysis calculated results. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)	The containment air locks satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).
LCO	Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.4, "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 air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is

(continued)

BASES

ACTIONS (continued)

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. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

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" if the overall containment leakage limits are exceeded.

<u>A.1, A.2, and A.3</u>

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 ACTION 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

(continued)

BASES

ACTIONS

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

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 both air locks have an inoperable door. This 7 day restriction begins when the second air lock 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).

(continued)

BASES

ACTIONS

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

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.

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

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time or in accordance with the Risk Informed Completion Time Program. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the 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. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES	1.	TS 5.5.16
	2.	UFSAR Sections 3.8 and 6.2 and Chapter 15.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are 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 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. In addition to the isolation signals listed above, the containment purge supply and exhaust valves, and containment pressure/vacuum relief isolation valves receive a Containment Ventilation Isolation (CVI) signal on a containment high radiation condition. In addition to these large valves, the containment gas and particulate radiation monitor penetrations also isolate upon receipt of a CVI signal. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

(continued)

BASES

BACKGROUND (continued)

Containment Purge System (48 inch purge valves)

The Containment Purge System operates to supply outside air into the containment for ventilation and cooling or heating needed for prolonged containment access following a shutdown and during refueling. The supply and exhaust lines each contain two isolation valves. The safety analyses assume that the 48-inch supply and exhaust line valves are closed at the start of the DBA. Therefore, the 48 inch Containment Purge supply and exhaust isolation valves are sealed closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Containment Pressure/Vacuum Relief (12 inch isolation valves)

The Containment Pressure/Vacuum Relief valves are operated as necessary to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access, and

b. Equalize containment internal and external pressures.

Since the 12 inch Containment Pressure/Vacuum Relief valves are designed to meet the requirements for automatic containment isolation within 5 seconds if mechanical blocks are installed to prevent opening more then 50°, these valves may be opened as needed in MODES 1, 2, 3, and 4.

(continued)

BASES (continued)

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 DBA that results in a release of radioactive material within containment in MODES 1, 2, 3, or 4 is a loss of coolant accident (LOCA) (Ref. 1). In the analyses for this accident, 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 the Containment Vacuum/Pressure Relief valves) are minimized. The safety analyses assume that the 48 inch purge valves are closed at event initiation. If the 12 inch pressure/vacuum relief valves close within 5 seconds after the DBA initiation, the safety analysis shows that offsite dose release will be less than 10 CFR 50.67 guidelines.
	The DBA analysis assumes that containment isolation occurs and leakage is prevented except for the design leakage rate, L_a.
	The LOCA offsite dose analysis assumes leakage from the containment at a maximum leak rate of 0.10 percent of the containment volume per day for the first 24 hours, and at 0.05 percent of the containment volume per day for the duration of the accident.
	The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the 12 inch Containment Pressure/Vacuum Relief valves. Two valves in series provide assurance that the flow paths can be isolated even if a single failure occurred. The inboard and outboard isolation valves are provided with diverse power sources and are pneumatically operated spring closed valves that will fail closed on the loss of power or air.
	The 12 inch Containment Pressure/Vacuum Relief valves are able to close in the environment following a LOCA. Therefore, each of the Containment Vacuum/pressure Relief valves may be opened to provide a flow path. The 12-inch vacuum/pressure relief valves may be open no more than 200 hours per calendar year while in MODES 1, 2, 3, and 4.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The system is designed to preclude a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO. The 48 inch Containment Purge supply and exhaust valves may be unable to close in the environment following a LOCA in sufficient time to support DBA acceptance criteria. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4. In this case, the single failure criterion remains applicable to the containment purge valves due to failure in the control circuit associated with each valve. Again, the purge system valve design precludes a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO. The containment isolation valves satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).
LCO	Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA. The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 48 inch Containment Purge supply and exhaust valves must be sealed closed during MODES 1, 2, 3 and 4. The Pressure/Vacuum Relief valves must have blocks installed to prevent full opening. These blocked valves also actuate on an automatic isolation signal. The valves covered by this LCO are listed along with their associated stroke times in Plant Procedure AD13.DC5 (Ref. 5) . Normally closed passive containment isolation valves/devices 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 5. Containment Purge supply and exhaust valves, and Containment Pressure/Vacuum Relief valves with resilient seals must meet additional leakage rate surveillance frequency requirements. The other containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment." This LCO provides assurance that the containment isolation valves and the Containment Purge supply and exhaust, and Containment Pressure/Vacuum Relief valves will perform their designed safety function to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

(continued)

BASES (continued)

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."

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except 48-inch purge valve flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a person at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment purge line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls. A single purge valve in a penetration flow path may be opened to effect repairs to an inoperable valve, as allowed by SR 3.6.3.1.

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 containment isolation valve leakage 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.

Plant Procedure AD13.DC5 Attachment 1 (Ref. 5) provides the applicable CONDITION to enter for each containment isolation valve if the valve is inoperable .

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths requiring isolation following a DBA is inoperable except for Containment Purge supply and exhaust, and Containment Pressure/Vacuum Relief isolation 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic isolation valve, a closed manual valve (this includes power operated valves with power removed), a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours or in accordance with the Risk Informed Completion Time Program. 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, which may include the use of local or remote indicators, that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days following isolation 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.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these devices once they have been verified to be in the proper position, is small.

B.1

With two containment isolation valves in one or more penetration flow paths requiring isolation following a DBA inoperable, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve (this includes power operated valves with power removed), 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.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths requiring isolation following a DBA 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 (this includes power operated valves with power removed), and a blind flange. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time or in accordance with the Risk Informed Completion Time Program. 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 (refer to UFSAR Table 6.2-39, GDC-57, 1971 valves). 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 following isolation 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 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.

(continued)

BASES

ACTIONS (continued)

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

In the event one or more Containment Purge supply and exhaust, or Containment Pressure/Vacuum Relief isolation valves in one or more penetration flow paths are not within leakage limits, leakage must be reduced to within limits, or the affected penetration flow path must be isolated. For this Action, the leakage limit is as specified under the Leakage Rate Testing Program and exceeding this limit would require evaluation per Note 4 under LCO 3.6.3. The method of isolation must be by 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, closed manual valve (this includes power operated valves with power removed), or blind flange. A Containment Purge supply and exhaust, or Containment Pressure/Vacuum Relief isolation valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.7. The specified Completion Time is reasonable, considering that one valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are 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 valve manipulation. Rather, it involves verification, through a system walkdown, which may include the use of local or remote indicators, that those isolation devices outside containment capable of being mispositioned are in the correct position. 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.

For the Containment Purge supply and exhaust, or Containment Pressure/Vacuum Relief isolation valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.7 must be performed at least once every 92 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase beyond the limits during the time the penetration is isolated. The normal Frequency for SR 3.6.3.7, is 24 months per the Containment Leakage Rate Testing Program. Since more reliance is placed on a single valve while in this

(continued)

BASES

ACTIONS

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

condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown to be acceptable based on operating experience.

Required Action D.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

E.1 and E.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 48 inch Containment Purge supply and exhaust valve is required to be verified sealed closed. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a Containment Purge valve. These valves are assumed to be closed at the start of a DBA. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A Containment Purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator. In the event the purge valve leakage requires entry into Condition D, the surveillance permits opening one purge valve in a penetration flow path to perform repairs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2

This SR ensures that the 12 inch Containment Pressure/Vacuum Relief valves are closed as required or, if open, open for an allowable reason. If a purge or pressure relief valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the Containment Pressure Relief valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The Containment Pressure/Vacuum Relief valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. 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 (continued)

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, which may include the use of local or remote indicators, 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 a 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 3.6.3.4

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.4 (continued)

administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in a 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 3.6.3.5

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 3.6.3.6

Not Used

SR 3.6.3.7

Containment Purge supply and exhaust, and Containment Pressure/Vacuum Relief valves with resilient seals, are leakage rate tested beyond the test requirements of 10 CFR 50, Appendix J, Option B to ensure OPERABILITY. Industry operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. 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 3.6.3.7 (continued)

A Note is added to clarify that Leakage Rate testing is not required for containment purge valves with resilient seals when their penetration flow path is isolated by a leak tested blank flange.

SR 3.6.3.8

Automatic containment isolation valves close on a containment isolation (Phase A, Phase B, or CVI) signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic valve will actuate to its isolation position on 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 3.6.3.9

Not Used

SR 3.6.3.10

Verifying that each 12 inch containment pressure/vacuum relief valve is blocked to restrict opening to ≤ 50° is required to ensure that the valves can close under DBA conditions within the times assumed in the analyses of References 1 and 2. If a LOCA occurs, the containment pressure/vacuum relief valves must close to maintain containment leakage within the values assumed in the accident analysis. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.3.11

Not Used

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Chapter 15
2. UFSAR, Section 6.2
3. Standard Review Plan 6.2.4
4. Generic Issue B-20, "Containment Leakage Due to Seal Deterioration"
5. Diablo Canyon Power Plant Administrative Procedure, AD13.DC5, "Control of the Surveillance Testing Program"
6. License Amendment 73/72, August 10, 1992
7. License Amendment 175/177, October 6, 2004

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System. Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.
APPLICABLE SAFETY ANALYSES	Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer modeled pressure transients.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1). The initial pressure condition used in the containment analysis was 16 psia (1.3 psig). This resulted in a maximum peak pressure from a SLB of 42.41 psig. The containment analysis (Ref. 1) shows that the maximum peak calculated containment pressure, results from the limiting SLB at 70% power. The maximum containment pressure resulting from the worst case SLB does not exceed the containment design pressure, 47 psig. The containment was also designed for an external pressure load equivalent to -3.5 psig. The inadvertent actuation of the Containment Spray System was analyzed to determine the resulting reduction in containment pressure (sudden cooling of -1.8 psid). The initial pressure condition used in this analysis was -1.7 psig. LCO 3.6.4 limits the operation of containment to equal to or less than -1.0 psig. This resulted in a minimum pressure inside containment of -2.8 psig, which is less than the design load. For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response. Containment pressure satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).
LCO	Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System.

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.
ACTIONS	<u>A.1</u> When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 4 hours. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 4 hour Completion Time is reasonable to return pressure to normal. <u>B.1 and B.2</u> If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.6.4.1</u> Verifying that containment pressure is within limits ensures that unit 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. Deleted.

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 and Cooling 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 that must be removed to avoid exceeding 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. A spectrum of SLBs were analyzed assuming the worst single active failure. The failure to close of one Main Steam Isolation Valve (MSIV) is the worst case single active failure for the SLB which results in the highest containment air temperature. 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 (Ref. 1) is 120°F.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The containment design temperature is 271°F. The containment structure was analyzed to withstand the maximum peak temperature for the limiting DBA LOCA to ensure that it can contain the release of radioactive materials resulting from the accident. The containment structure was not analyzed for SLBs which were not considered design basis for containment structural design. The spectrum of SLBs cases are used to establish the environmental qualification operating envelope inside containment. The analysis shows that the peak containment temperature is 312.4°F (experienced during the MSLB at 0 % power). The performance of required PG&E Design Class I equipment is evaluated against this operating envelope to ensure the equipment can perform its safety function (Ref. 2). The temperature limit is also used in the Containment external pressure analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray 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 temperature limit is used in this 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).
LCO	During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant accident temperature profile assures that the containment structural temperature will be maintained below the containment design temperature and that required PG&E Design Class I equipment within containment will continue to perform its function. As a result, the ability of containment and PG&E Design Class I equipment within containment to perform its design function is ensured.

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.
ACTIONS	<u>A.1</u> When containment average air temperature is not within the limit of the LCO, it must be restored to within limit 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. <u>B.1 and B.2</u> If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using four temperature measurements. The four temperature measurement locations are pre-selected from:

a. TE-85 or TE-86, approximately 100 ft elevation between crane wall and containment wall,

b. TE-87 or TE-88, approximately 100 ft elevation between steam generators,

c. TE-89 or TE-90, approximately 140 ft elevation near equipment hatch or stairs at 270°, respectively,

d. TE-91 or TE-92, approximately 184 ft elevation on top of steam generator missile barriers away from steam generators.

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 Containment Spray and Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Cooling systems provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The design bases of the Containment Spray and Containment Cooling systems are discussed in UFSAR Sections 6.2.2, 6.2.3, and 6.2.5 (References 1, 3, and 4).

As discussed in UFSAR Appendix 3.1A (Ref. 10), the designs of these systems conform to the intent of 10 CFR 50, Appendix A, GDCs 38, “Containment Heat Removal”; GDC 39, “Inspection of Containment Heat Removal Systems”; GDC 40, “Testing of Containment Heat Removal Systems”; GDC 41, “Containment Atmosphere Cleanup”; GDC 42, “Inspection of Containment Atmosphere Cleanup Systems”; and GDC 43, “Testing of Containment Atmosphere Cleanup Systems.”

The Containment Cooling System and Containment Spray System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System and the Containment Cooling System provide diverse methods to limit and maintain post accident conditions to less than the containment design values.

<u>Containment Spray System</u>

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the design bases. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation.

(continued)

BASES

BACKGROUND

Containment Spray System (continued)

In the recirculation mode of operation, containment spray is supplied by manual realignment of the residual heat removal (RHR) pumps after the RWST is empty.

The Containment Spray System provides a spray of cold borated water mixed with sodium hydroxide (NaOH) from the spray additive tank into the upper regions of containment to reduce the containment pressure and temperature, and to reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump water by the RHR heat exchangers. Each train of the Containment Spray System provides adequate spray coverage to meet the system design requirements for containment atmospheric heat removal.

The Spray Additive System injects an NaOH solution into the spray. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The NaOH added in the spray also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water maximizes the retention of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-High pressure signal or manually. If an "S" signal is present, the High-High pressure signal automatically starts the two containment spray pumps, opens the containment spray pump discharge valves, opens the spray additive tank outlet valves, initiates a phase "B" isolation signal, and begins the injection phase. A manual actuation of the Containment Spray System will begin the same sequence and can be initiated by operator action from the main control board. The injection phase of containment spray continues until an RWST Low-Low level alarm is received. The Low-Low level alarm for the RWST signals the operator to manually secure the system. After re-alignment of the RHR system to the containment recirculation sump, the associated RHR spray header isolation valve is opened to allow continued spray operation of one train of spray utilizing the RHR pump to supply flow. The LOCA dose analysis takes credit for this manual initiation of Containment Spray during recirculation to take place within 12 minutes following the termination of Containment Spray during the injection phase.

(continued)

BASES

BACKGROUND

Containment Spray System (continued)

Containment Spray is required to be actuated during the recirculation phase of a LOCA. Containment Spray operation (injection plus recirculation) is credited until 6.25 hours following initiation of a LOCA. The 6.25 hours accounts for the containment spray pumps startup time after accident initiation and the momentary containment spray shutdown time during switchover of the containment spray function from the containment spray pumps during injection phase to containment spray functions being provided by the RHR system during recirculation phase. During the recirculation phase of a LOCA, the Containment Spray System must be capable of transferring the spray function to an RHR System taking suction from the containment sump. OPERABILITY of valves 9003A and B, and the capability to close valves 8809A and B to divert water from the RCS to the spray headers, will ensure that this capability exists.

Containment Cooling System

Two trains of containment fan cooling, each consisting of two CFCUs with one shared CFCU for a total of five, are provided. The five CFCUs are powered from three separate Class 1E buses, with two CFCUs on each of two Class 1E buses and the remaining CFCU from the third Class 1E bus. Each CFCU is supplied with cooling water from one of two separate loops of component cooling water (CCW). Air is drawn into the coolers through the fan and discharged to the annulus ring which supplies the steam generator compartments, pressurizer compartment, reactor coolant pumps, and outside the secondary shield in the lower areas of containment.

During normal operation, three CFCUs are operating. The fans are normally operated at high speed with CCW supplied to the cooling coils. The CFCUs are designed to limit the ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, the CFCUs are designed to start automatically in slow speed if not already running. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. The temperature of the CCW is an important factor in the heat removal capability of the fan units.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limits the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the main steam line break (MSLB). The LOCA and MSLB 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 regard to containment ESF systems, assuming the worst case single failure. For the LOCA case, the worst single failure is the failure of one SSPS train, which results in only one CSP and two CFCUs available. For SLB case, the worst single failure is the failure of one MSIV to close with two CSP and three CFCUs operating. The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 42.41 psig (experienced during an MSLB at 70% power) compared to an allowable 47 psig. The analysis shows that the peak containment temperature is 312.4°F (experienced during an MSLB at 0% power) and is compared to the environmental qualifications of plant equipment. Both results meet the intent of the design basis (refer to the Bases for LCO 3.6.4, “Containment Pressure,” and LCO 3.6.5 for a detailed discussion). The analyses and evaluations assume a unit specific power level of 102% for the LOCA with one containment spray train and two CFCUs operating. The limiting case MSLB analyses and evaluations are based upon a unit specific power level of 0% or 70% with two containment spray trains and three CFCUs operating. The peak pressure case assumes a failure of the feedwater regulating valve in the faulted loop, and the peak temperature case assumes a failure of the MSIV in the faulted loop. Initial (pre-accident) containment conditions of 120°F and 1.3 psig are assumed. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Analyses and evaluation show that containment spray is not required during the recirculation phase of a LOCA for containment pressure and temperature control (Ref. 7). However, for dose consequences, containment spray is required during the recirculation phase of a LOCA for removing radioactive iodine and particulates from the containment atmosphere. If only one RHR pump is available during the recirculation phase of a LOCA, it may not be possible to obtain significant containment spray without closing valves 8809A or B. If recirculation spray is used with only one train of RHR in operation, ECCS flow to the reactor will be reduced, but analysis has shown that the flow to the reactor in this situation is still in excess of that needed to supply the required core cooling. The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in a -1.80 psid containment pressure decrease and is based on a sudden cooling effect of 70°F in the interior of the leak tight containment. Additional discussion is provided in the Bases for LCO 3.6.4. The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment High-High pressure setpoint to achieving full flow through the containment spray nozzles. The Containment Spray System total response time includes diesel generator (DG) startup (for loss of offsite power),

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	sequenced loading of equipment, containment spray pump startup, and spray line filling (Ref. 1). The CFCUs performance for post accident conditions is given in Reference 1. The result of the analysis is that each train (two CFCUs) combined with one train of containment spray can provide 100% of the required peak cooling capacity during the post accident condition. The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with exceeding the containment High-High pressure setpoint to achieving full Containment Cooling System air and safety grade cooling water flow. The Containment Cooling System total response time includes signal delay, DG startup (for loss of offsite power), and component cooling water pump startup times. The Containment Spray System and the Containment Cooling System satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).
LCO	During a DBA LOCA, a minimum of two CFCUs and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 1). Additionally, one containment spray train is also required to remove radioactive iodine and particulates from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two containment spray trains and the CFCU system consisting of four CFCUs or three CFCUs each supplied by a different Class 1E bus must be OPERABLE. Therefore, in the event of an accident, at least one train of containment spray and two CFCUs operate, assuming the worst case single active failure occurs. Each Containment Spray train typically includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal. Upon actuation of the RWST Low-Low alarm, the containment spray pumps are secured. Containment spray is then supplied by an RHR pump taking suction from the containment sump for a total spray operation (injection and recirculation) of 6.25 hours after accident initiation. The 6.25 hours accounts for the containment spray pumps startup time after accident initiation and the momentary containment spray shutdown time during switchover of the containment spray function from the containment spray pumps during injection phase to containment spray function being provided by the RHR system during recirculation phase. Management of gas voids is important to Containment Spray System OPERABILITY. Each CFCU includes cooling coils, dampers, fans, instruments, and controls to ensure an OPERABLE flow path.

(continued)

BASES (continued)

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 containment spray trains and CFCUs.

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 Containment Spray System and the Containment Cooling System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 54 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 9). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 9, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 4 allows 48 hours to restore the containment spray train to OPERABLE status in MODE 3. This is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

(continued)

BASES

ACTIONS (continued)

C.1

With one CFCU system inoperable such that a minimum of two CFCUs remain operable, restore the required CFCUs to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. The components in this degraded condition are capable of providing at least 100% of the heat removal needs. The 7 day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System and the low probability of DBA occurring during this period.

D.1 and D.2

With one train of containment spray inoperable and the CFCUs system inoperable such that a minimum of two CFCUs remain OPERABLE, restore one required train of containment spray or CFCU system to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. The components remaining in OPERABLE status in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System, the iodine removal function of the Containment Spray System, and the low probability of DBA occurring during this period.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C or D of this LCO are not met, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 9). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 9, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

Required Action E.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

F.1

With two containment spray trains or one containment spray train inoperable and two CFCU systems inoperable such that one or less CFCUs remain OPERABLE or one or less CFCUs are OPERABLE, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. The containment spray flow path consists of the direct flow path from the fluid source (e.g., RWST) to the supplied PG&E Design Class I component (e.g., spray headers) and portions of any branch line flow path off the direct flow path that a valve misposition could result in degradation of the system safety function. 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. This SR also does not apply to valves which are closed and secured by a cap or blind flange (e.g., manual test, vent, and drain valves), to valves that cannot be inadvertently misaligned (e.g., check valves), or to valves in instrument or sample lines. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, which may include the use of local or remote indicators, that those valves outside containment (only check valves are inside 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.

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

SR 3.6.6.2

Operating each required CFCU for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3

Verifying that each required CFCU is receiving the required component cooling water flow of ≥ 1650 gpm provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 1). The component cooling water (CCW) system is hydraulically balanced during normal operation to ensure that at least 1650 gpm is delivered to each CFCU during a design bases event (DBA). The hydraulic system balance considers normal system alignments and the potential for any single active failure.

Operation of the CFCUs is permitted with lower CCW flow to the CFCUs during ASME Section XI testing or decay heat removal in MODE 4 with the residual heat removal heat exchangers in service. To support this conclusion, a calculation was performed to evaluate containment heat removal with one train of containment spray OPERABLE and reduced CCW flow to three CFCUs. The calculation concluded that this configuration would provide adequate heat removal to ensure that the maximum design pressure of containment was not exceeded during a DBA in MODE 1. This analysis also determined that a single failure could not be tolerated during this condition and still assure that the maximum design pressure of containment would not be exceeded. (Ref. 6)

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

SR 3.6.6.4

Containment Spray System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the containment spray trains and may also prevent water hammer and pump cavitation.

Selection of Containment Spray System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.4 (continued)

Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The Containment Spray System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. If it is determined by subsequent evaluation that the Containment Spray System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

Containment Spray System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.5

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head (205 psid) ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME O&M Code (Ref. 5). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. During refueling operation, a containment spray pump can be aligned to take suction from the refueling water storage tank (RWST) and discharge into the residual heat removal system discharge line back to the RWST. Flow using this lineup can achieve full design flow of 2600 gpm. 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 abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.6.6.6 and SR 3.6.6.7

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment high-high pressure signal with a coincident "S" 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.8

This SR requires verification that each CFCU actuates upon receipt of an actual or simulated safety injection signal. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.9

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.10

The CFCUs are designed to start or restart in low speed upon receipt of an SI signal. This SR ensures that this feature is functioning properly. 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
2. Deleted.
3. UFSAR, Section 6.2.3
4. UFSAR, Section 6.2.5
5. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2004 Edition including 2005 and 2006 Addenda
6. License Amendment 89/88, April 16, 1996
7. Not Used.
8. License Amendment 202/203, December 31, 2008
9. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010
10. UFSAR, Appendix 3.1A

(continued)

BASES

REFERENCES (continued)	11. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, “Generic Letter 2008-01, Managing Gas Accumulation,” Using the Consolidated Line Item Improvement Process.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA LOCA).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray droplets 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 8.0 and 9.5 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 Spray Additive System consists of one spray additive tank that is shared by the two trains of spray additive equipment. Each train of equipment provides a flow path from the spray additive tank to a containment spray pump and consists of an eductor for each containment spray pump, valves, instrumentation, and connecting piping. Each eductor draws the NaOH spray solution from the common tank using a portion of the borated water discharged by the containment spray pump as the motive flow. The eductor mixes the NaOH solution and the borated water and discharges the mixture into the spray pump suction line.

The Containment Spray System actuation signal opens the valves from the spray additive tank to the spray pump suctions or a manual containment spray initiation signal also opens the valves from the spray additive tank. The 30% to 32% NaOH by weight solution is drawn into the spray eductor suctions which inject it into the spray pump suction. The spray additive 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 sprayed into containment ensures a long term containment sump pH of ≥ 8.0 and ≤ 9.5. This ensures the continued iodine retention effectiveness of the sump water during the recirculation phase of operation and also minimizes the occurrence of chloride induced stress corrosion cracking of the stainless steel recirculation piping.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The Spray Additive System is essential to the removal of airborne iodine within containment following a DBA LOCA. Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value volume following the accident. The analysis assumes that a minimum 83% of the containment free volume is covered by the spray (Ref. 1). The DBA response time assumed for the Spray Additive System is the same as for the Containment Spray System and is discussed in the Bases for LCO 3.6.6, "Containment Spray and Cooling Systems." The DBA analyses assume that one train of the Containment Spray System/Spray Additive System is inoperable in which case spray additive solution is added using only the remaining Containment Spray System flow path. In this case, by the time the RWST reaches low-low level and the addition of spray additive solution is terminated, a sufficient volume of spray additive solution will have been discharged into the containment to raise the pH of the water in Containment above the minimum required value. The Spray Additive System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
LCO	The Spray Additive System is necessary to reduce the release of radioactive material to the environment in the event of a DBA LOCA. To be considered OPERABLE, the volume and concentration of the spray additive solution must be sufficient to provide NaOH injection into the spray flow to raise the average long term containment sump solution pH to a level conducive to iodine retention in the liquid phase, namely, to between 8.0 and 9.5. This pH range maximizes the effectiveness of the iodine removal mechanism (from the containment atmosphere) without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. In addition, it is essential that valves in the Spray Additive 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 LOCA could cause a release of radioactive material to containment requiring the operation of the Spray Additive System. The Spray Additive System assists in reducing the containment atmosphere 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 Spray Additive System is not required to be OPERABLE in MODE 5 or 6.

(continued)

BASES

ACTIONS

A.1

If the Spray Additive System is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the Containment Spray System flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment 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 redundant flow path capabilities and the low probability of the worst case DBA occurring during this period.

B.1 and B.2

If the Spray Additive System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 54 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 4 allows 48 hours to restore the Spray Additive System to OPERABLE status in MODE 3. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of Spray Additive System manual, power operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. The spray additive flow path consists of the direct flow path from the fluid source (e.g., spray additive tank) to the supplied PG&E Design Class I component (e.g., spray headers) and portions of any branch line flow path off the direct flow path that a valve misposition could result in degradation of the system safety function. 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 also does not apply to valves which are closed and secured by a cap or blind flange (e.g., manual test, vent, and drain valves), to valves that cannot be inadvertently misaligned (e.g., check valves), or to valves in instrument or sample lines. This SR does not require any testing or valve manipulation. Rather, it involves verification through a system walkdown, which may include the use of local or remote indicators, 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive 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 Spray Additive System. The required volume may be surveilled using an indicated level band of 50 to 88% for the Spray Additive Tank which corresponds to the LCO 3.6.7 minimum and maximum limits adjusted conservatively for instrument accuracy of ± 3%. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected 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 3.6.7.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position on a containment spray actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.6.7.5 To ensure correct operation of the Spray Additive System, flow from the spray additive tank to the eductors is verified. This SR is performed by verifying that the solution flow path is not blocked from the spray additive tank through test valve 8993, from the RWST through test valve 8993 for each of the two flow paths, and from the RWST to the eductors. This SR provides assurance that NaOH will be metered into the flow path upon Containment 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	1. UFSAR, Section 6.2. 2. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Not used

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 10.3.2 (Ref. 1). The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure. The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves during an overpressure event.
APPLICABLE SAFETY ANALYSES	The design basis for 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, Sections 15.2 and 15.3 (Ref. 3). Of these, the full power turbine trip without steam dump is the limiting AOO with respect to secondary system pressure. This event also terminates normal feedwater flow to the steam generators. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	One turbine trip analysis is performed assuming primary system pressure control via operation of the pressurizer relief valves and sprays. The 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 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. The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening, and failure to reclose once opened. The passive failure mode is failure to open upon demand. The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The accident analysis requires that five MSSVs per steam generator be OPERABLE to provide overpressure protection for design basis transients occurring at 102% RTP. The LCO requires that five MSSVs per steam generator be OPERABLE in compliance with Reference 2. 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 verified 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 limit secondary pressure. 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.

(continued)

BASES (continued)

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1

With one or more MSSVs inoperable, action must be taken so that the available MSSV relieving capacity meets Reference 2 requirements.

Continued 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 and the Power Range Neutron Flux trip setpoint so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator.

The Reactor Trip Setpoint reductions applied in TS Table 3.7.1-1 are derived on the following bases:

One MSSV Inoperable

The limiting UFSAR Condition II accident for overpressure concerns is a loss of external load/turbine trip (LOL/TT). The event is analyzed with the RETRAN-02 computer program to demonstrate the adequacy of the MSSVs to maintain the main steam system lower than 1210 psia, or 110% of the 1085 psig SG design pressure when crediting only the Pressurizer Pressure High reactor trip.

In a Westinghouse calculation, the LOL/TT transient is reanalyzed with the comparable RETRAN-02W code to determine the effect of only four MSSVs per SG being available when crediting the Overtemperature ΔT trip. The analysis assumes a 3% tolerance for all the available MSSVs. The MSSV on each SG with the lowest nominal setpoint was assumed unavailable, and the Unit 2 results are reported because it is slightly more limiting with a higher design RCS average temperature. The results of the calculation show that the peak pressures in the SGs are lower than 1210 psia, or 110% of the 1085 psig SG design pressure for a range of power levels and moderator temperature coefficients that bound a Power Range Neutron Flux trip setpoint of 87 % RTP (Ref. 8).

Thus, with one MSSV inoperable per SG, the remaining MSSVs are capable of providing sufficient pressure relief capacity for the plant to operate at 100% RATED THERMAL POWER (RTP). However, the value applied to the high neutron flux trip setpoints must be lowered an additional 6% RTP to account for instrument and channel uncertainties (Ref. 7). This adjustment results in a setpoint of 94% RTP; however, the setpoint will remain at 87% RTP for additional conservatism.

(continued)

BASES

ACTIONS

A.1 (continued)

The additional footnotes ensure the guidance provided in Regulatory Issue Summary 2006-17 (Ref. 11) are met and that the methodologies used to determine the as-found and the as-left tolerances are specified in a procedure controlled under 10 CFR 50.59.

More than One MSSV Inoperable

For more than one MSSV on each loop inoperable, the following Westinghouse algorithm contained in NSAL 94-001 (Ref. 4) is used:

$$\text{Hi } \Phi = (100/Q)\frac{(w_g h_{fg} N)}{K}$$

where:

Hi Φ = Safety Analysis PR high neutron flux setpoint, percent

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat), MWt

K = Conversion factor, 947.82 (Btu/sec)/MWt

w_s = Minimum total steam flow rate capability of the operable MSSVs on any one SG at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, in lb/sec. For example, if the maximum number of inoperable MSSVs per SG is three, then w_s should be a summation of the capacity of the operable MSSVs at the highest operable MSSV operating pressure, excluding the three highest capacity MSSVs.

h_{fg} = heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, Btu/lbm

N = Number of loops in plant

For the case of two and three inoperable MSSVs per SG, the setpoints derived are 53% and 35% RTP, respectively. However, the values applied to the high neutron flux trip setpoints must be lowered an additional 6% RTP to account for instrument and channel uncertainties (Ref. 7), which results in setpoints of 47% and 29% RTP, respectively (Ref. 9).

When a MSSV(s) is inoperable, the power must be reduced in 4 hours to a value less than or equal to the value specified in table 3.7.1-1, corresponding to the number of OPERABLE MSSVs.

The Power Range Neutron Flux-high trip setpoint must also be reduced in 4 hours, to less than or equal to the value specified in Table 3.7.1-1, corresponding to the number of OPERABLE MSSVs.

(continued)

BASES

ACTIONS

A.1 (continued)

The allowed Completion Time is reasonable base on operating experience to complete the Required Actions in an orderly manner without challenging unit systems.

B.1 and B.2

If THERMAL POWER and Power Range Neutron Flux Trip are not reduced as required by Table 3.7.1-1 within the associated Completion Time, or if one or more steam generators have less than two MSSVs OPERABLE, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI (Ref. 5), requires that safety and relief valve tests be performed in accordance with ASME OM Code Appendix I (Ref. 6). According to Reference 6, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting);

d. Compliance with owner's seat tightness criteria; and

e. Verification of the balancing device integrity on balanced valves.

The ASME OM Code requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 3% setpoint (as-found lift point) tolerance on the valves for OPERABILITY (with the exception of the lowest set MSSV setpoint, which is (+3%/-2%); however, the valves are reset to ± 1% during the Surveillance to allow for drift. The lift settings, according to Table 3.7.1-2 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.7.1.1</u> (continued) This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. UFSAR, Section 10.3.2
2. ASME Boiler and Pressure Vessel Code, Section III, 1968.
3. UFSAR, Sections 15.2 and 15.3
4. Westinghouse Nuclear Safety Advisory Letter NSAL-94-001, “Operation at Reduced Power Levels with Inoperable MSSVs,” January 20, 1994 (included in NRC Information Notice IN-94-60, "Potential Overpressurization of the Main Steam System," August 22, 1994.
5. ASME, Boiler and Pressure Vessel Code, Section XI.
6. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2004 Edition including 2005 and 2006 Addenda
7. Westinghouse Report WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems Diablo Canyon Units 1 and 2, 24 Month Fuel Cycle Program and Replacement Steam Generator Evaluation”
8. Westinghouse Letter PGE-10-43, “Diablo Canyon Units 1 and 2 Loss of Load / Turbine Trip Analysis with One Inoperable MSSV per Steam Generator,” dated September 2, 2010.
9. PG&E Design Calculation N-115, "Reduced Power Levels for A Number of MSSVs Inoperable," dated 3/14/94.
10. None
11. NRC Regulatory Issue Summary (RIS) 2006-17, "NRC Staff Position on the Requirements of 10 CFR 50.36, ‘Technical Specifications,’ Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels," dated August 24, 2006

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND	The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators. One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are installed back to back with the main steam reverse flow check valves. The MSIVs 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 MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Steam Bypass System, and other auxiliary steam supplies from the steam generators. The MSIVs close on a main steam isolation signal generated by high negative steam line pressure rate or low steam line pressure or high-high containment pressure. The MSIVs are held in the open position and will fail in the closed direction on loss of control air and fail open on loss of actuation power. Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually. A description of the MSIVs is found in the UFSAR, Section 10.3 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the UFSAR Appendix 6.2 D (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 MSIV to close on demand). Each MSIV is provided with a main steam reverse flow check valve to prevent the blowdown of two steam generators in the event of a SLB upstream of an MSIV with the failure of an MSIV to close on demand in another steam generator. The limiting case for the containment pressure analysis is the SLB inside containment, with initial reactor power at 30% with no loss of offsite power, and failure of the MSIV on the affected steam generator to close. At lower powers, the steam generator inventory and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to the assumed reverse flow (the MSIV reverse flow check valves are not credited to function even though they are PG&E Design Class I) and failure of the affected steam generator's MSIV to close, the additional mass and energy in the steam headers downstream from the other MSIVs is conservatively assumed to contribute to the total release. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB 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 MSIV to close.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. An HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For conservatism for this accident scenario, no credit is taken for closure of the affected steam generator MSIV reverse flow check valve and steam is assumed to be discharged into containment from all steam generators until the MSIVs close in the unaffected loops. After the MSIVs close in the unaffected loops, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs in the unaffected loops isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that four MSIVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 50.67 (Ref. 4) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed and de-activated (vented or prevented from opening), when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, the steam generator energy is low, thus OPERABILITY in MODE 4 is not required.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours or in accordance with the Risk Informed Completion Time Program. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional means for containment isolation.

(continued)

BASES

ACTIONS (continued)

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition C would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis. MSIV closure is indicated by the control room valve indicating lights or monitor light box lights.

The 8 hour Completion Time is consistent with that allowed in Condition A.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 5.0 seconds. The remote manual hand switch may be used as the actuation signal for this SR. The MSIV closure time is assumed in the accident and containment

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.7.2.1</u> (continued) analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MSIVs 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 MSIVs are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 5), requirements during operation in MODE 1 or 2. The Frequency is in accordance with the Inservice Testing Program. 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. However, the test is normally conducted in MODE 5 as permitted by the cold shutdown frequency justification provided in the Inservice Testing Program (IST) and as permitted by Reference 6, Subsection ISTC-3521(c). <u>SR 3.7.2.2</u> This SR verifies that each MSIV 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 10.3 2. UFSAR, Appendix 6.2 D 3. UFSAR, Section 15.4.2 4. 10 CFR 50.67. 5. ASME, Boiler and Pressure Vessel Code, Section XI. 6. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2004 Edition including 2005 and 2006 Addenda

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs), Main Feedwater Regulating Valves (MFRVs), MFRV Bypass Valves, and Main Feedwater Pump (MFWP) Turbine Stop Valves

BASES

BACKGROUND

The PG&E Design Class I function of the MFRVs and the MFRV bypass valves is to provide the initial isolation of main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). Since the MFRVs and MFRV bypass valves are located in non-PG&E Design Class I piping, the MFIVs also provide PG&E Design Class I isolation of the MFW flow to the secondary side of the steam generators a short time later. Closure of the MFRVs and MFRV bypass valves or tripping of the MFWPs and closure of the MFIVs a short time later terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs or MFRVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFRVs and MFRV bypass valves, or tripping of the MFWPs and closure of the MFIVs a short time later effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The MFIVs isolate the non-PG&E Design Class I portions from the PG&E Design Class I portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFIV and one MFRV and MFRV bypass valve, are located on each MFW line, outside but close to containment. The MFIVs and MFRVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MFIV or MFRV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

(continued)

BASES

BACKGROUND (continued)	The MFIVs and MFRVs and MFRV bypass valves, close on receipt of any safety injection (SI) signal, or steam generator (S/G) water level - high high signal. They may also be actuated manually. The MFWP turbine is also tripped upon receipt of an SI or S/G water level - high high signal (as well as other pump related trips), however, these are PG&E Design Class II trips and are only credited as a backup to the single failure of a MFRV and MFRV bypass valve trip. The MFRVs and MFRV bypass valves also close on receipt of a T_{avg} - Low coincident with reactor trip (P-4). In addition to the MFIVs and the MFRVs and MFRV bypass valves, a check valve located upstream of the MFIV is available. The check valve isolates the feedwater line, penetrating containment, and ensures that the intact steam generators do not continue to feed the feedwater line break in the non-PG&E Design Class I piping upstream of the feedwater isolation check valves and that the AFW flow will be to the steam generators. A description of the MFIVs, MFRVs, and MFRV bypass valves is found in the FSAR, Section 10.4.7 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The design basis of the MFIVs, MFRVs, and MFRV bypass valves is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFRVs and MFRV bypass valves, or tripping of the MFWPs and closure of the MFIVs a short time later, is relied on to terminate an SLB for core and containment response analysis and excess feedwater event upon the receipt of a feedwater isolation signal on high-high steam generator level. Failure of an MFIV, MFRV, or the MFRV bypass valves to close, or failure of the MFWPs to trip, following an SLB 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 SLB or FWLB event. The MFIVs, MFRVs, MFRV bypass valves, and MFWP trip satisfy Criterion 3 of 10 CFR 50.36 (c) (2) (ii).
LCO	This LCO ensures that the MFIVs, MFRVs and MFRV bypass valves, and tripping of the MFWPs, will isolate MFW flow to the steam generators, following an FWLB or main steam line break, or an excessive feedwater event. The MFIVs will also isolate the non-PG&E Design Class I portions from the PG&E Design Class I portions of the system.

(continued)

BASES

LCO (continued)

This LCO requires that four MFIVs, four MFRVs and four MFRV bypass valves be OPERABLE. The MFIVs and MFRVs and MFRV bypass valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

This LCO also requires that the MFWP turbine stop valves be OPERABLE. The MFWP turbine stop valves are considered OPERABLE when their closure times are within limit and they close on a feedwater isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. A feedwater isolation signal on 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.

APPLICABILITY

The MFIVs, MFRVs, MFRV bypass valves, and the MFWP turbine stop valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1, 2, and 3, the MFIVs, MFRVs, MFRV bypass valves, and the MFWP turbine stop valves are required to be OPERABLE to limit the amount of available fluid that could be added to the steam generators in the case of a secondary system pipe break inside containment or an excessive feedwater event. They are not required to be OPERABLE when the MFIVs, MFRVs, and MFRV bypass valves are closed and deactivated or isolated by a closed manual valve, or when the MFWP turbine stop valves are closed and the steam supplies to the MFWP turbine stop valves are isolated, or the MFWP discharge to the steam generators is isolated by a closed manual valve.

When the MFIVs, MFRVs, and MFRV bypass valves are closed and deactivated or isolated by a closed manual valve, they are already performing their safety function. A single MFWP is operated at low power levels. It is placed in service and taken out of service at approximately 2 percent power. Before a MFWP is placed in operation, the MFWP turbine stop valves are closed and the high pressure and low pressure steam supplies to the MFWP turbine are isolated. When the MFWP turbine stop valves are closed and the steam supplies to the MFWP turbine stop valves are isolated, or the MFWP discharge to the steam generators is isolated by a closed manual valve, the safety function of the MFWP turbine stop valves is being performed.

(continued)

BASES

APPLICABILITY (continued)	In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs, MFRVs, and MFRV bypass valves are normally closed and the MFWPs are tripped since MFW is not required.

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 PG&E Design Class II main feedwater pump trip and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

B.1 and B.2

With one MFRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the PG&E Design Class II main feedwater pump trip 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.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Inoperable MFRVs, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

C.1 and C.2

With one MFRV bypass valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the PG&E Design Class II main feedwater pump trip and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRV bypass valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

D.1.1, D.1.2, D.1.3, and D.2

With one MFWP turbine stop valve inoperable, action must be taken to restore the affected valve to OPERABLE status or close the affected valve, trip the MFWP, or isolate the MFWP discharge within 72 hours. When the MFWP turbine stop valve is closed, the MFWP is tripped, or the MFWP discharge to the steam generators is isolated, the feedwater isolation safety function is being performed.

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 termination of MFW flow. The 72 hour Completion Time is reasonable, based on operating experience.

(continued)

BASES

ACTIONS

D.1.1, D.1.2, D.1.3, and D.2 (continued)

Closure of the MFWP turbine stop valve, trip of the MFWP, or isolation of the MFWP discharge must be verified on a periodic basis to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve or pump status indicators available in the control room, and other administrative controls, to ensure that the MFWP turbine stop valve is closed, the MFWP is tripped, or the MFWP discharge is isolated.

E.1

With either a MFRV or MFRV bypass valve and MFIV inoperable, or MFWP turbine stop valve (resulting in a loss of MFWP trip function) and MFRV or MFRV bypass valve inoperable, there may be no redundant system to operate automatically and perform the required safety function. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. With both a MFWP turbine stop valve and MFIV inoperable, the MFRV and MFRV bypass valve will operate automatically to provide feedwater isolation for the flow path. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MFIV, MFRV, MFRV bypass valve, or MFWP turbine stop valve, or otherwise isolate the affected flow path.

F.1 and F.2

If the MFIV(s), MFRV(s) and the MFRV bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated, or the MFWP turbine stop valve(s) cannot be restored to an OPERABLE status, closed, the MFWP tripped, or the MFWP discharge 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 and SR 3.7.3.2

These SRs verify that the closure time of each MFIV is ≤ 60 seconds and that each MFRV, and MFRV bypass valves is ≤ 7 seconds, not including the instrument delays. The MFIV and MFRV and MFRV bypass valve closure times are assumed in the accident and containment analyses. These Surveillances are normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code (Ref. 2) stroke requirements during operation in MODES 1 and 2.

The Frequency for these SRs is in accordance with the Inservice Testing Program.

SR 3.7.3.3

This SR verifies that each MFIV, MFRV, MFRV bypass valve, and MFWP turbine stop valve can close 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 3.7.3.4

This SR verifies that the closure time of each MFWP turbine stop valve is ≤ 1 second, not including the instrument delays. The MFWP turbine stop valve closure times are assumed in the accident and containment analyses. These surveillances are normally performed on returning the unit to operation following a refueling outage. The Frequency is the same as that for the MFRVs and the MFRV bypass valves. Preventive/predictive maintenance related to the MFWP turbine stop valves, and actions initiated in response to control oil cleanliness problems, shall be performed to ensure reliability of MFWP trip function.

REFERENCES

1. UFSAR, Section 10.4.7
2. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2004 Edition including 2005 and 2006 Addenda

B 3.7 PLANT SYSTEMS

B 3.7.4 10% Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND	The 10% ADVs (PCV-19, PCV-20, PCV-21 and PCV-22) provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the 40% steam dump valves to the condenser not be available, as discussed in the UFSAR, Chapter 15 (Ref 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the Condensate storage tank (CST). The ADVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the 40% steam dump valves. One ADV line for each of the four steam generators is provided. Each ADV line consists of one ADV and an associated manual block valve. The ADVs are provided with upstream manual block valves to permit their being tested at power, and to provide an alternate means of isolation. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate. The ADVs are normally provided with a non-PG&E Design Class I pressurized supply of air. With a loss of pressure in the normal air supply the backup non-PG&E Design Class I nitrogen supply, automatically supplies to operate the ADVs. With the loss of both the normal air supply and the backup nitrogen supply, the normal supplies are blocked and the PG&E Design Class I backup air bottle system is activated. With the backup air bottle system activated, control of the valves is remote manual via the PG&E Design Class I control circuit from the Control Room. The bottled air supply is sized to provide sufficient pressurized gas to operate the ADVs for the time required for Reactor Coolant System cooldown to RHR entry conditions. In addition, handwheels are provided for local manual operation.
APPLICABLE SAFETY ANALYSES	The design basis of the ADVs is established by the capability to cool the unit to RHR entry conditions at the maximum allowable rate of 100°F per hour. The ADVs support the AFW cooldown function from normal zero-load temperature in the RCS to a hot-leg temperature of 350°F (which is the maximum temperature allowed for placing the RHR system in service). Various cooldown rates are applicable depending upon the event and the assumed available equipment. These rates vary from a high of 100°F/hr for the SGTR event to 25°F/hr for a natural circulation cooldown event utilizing the cooling water supply available in the CST.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The ADVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for events accompanied by a loss of offsite power. Prior to operator actions to cool down the unit, the ADVs 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 and thus limit offsite dose, is more critical than the time required to cool down to RHR conditions for this event and also for other events. Thus, the SGTR is the limiting event for the ADVs. All four ADVs are required to be OPERABLE to satisfy the SGTR accident analysis requirements since the SGTR event assumes that the ADV on the faulted SG fails open to maximize the offsite dose and that the three intact SGs are utilized to cool the RCS at the Maximum allowable rate of 100°F/hr.

The once per 24 hour verification that backup air bottle pressure is greater than or equal to 260 psig assures that the ADVs will perform as required by the applicable safety analyses.

The ADVs are equipped with manual block valves in the event an ADV spuriously fails open or fails to close during use.

The ADVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Four ADV lines are required to be OPERABLE. One ADV line is required from each of four steam generators to ensure that at least two ADV lines are available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a single, active failure of an ADV on an unaffected steam generator. The block valves must be OPERABLE to isolate the failed open ADV line. A closed block valve renders its ADV line inoperable, and the appropriate ACTION must be entered until such time that the block valve is opened. Each ADV must have its associated backup air bottle OPERABLE along with its manual controls from the control room. This backup assures operation during cooldown to RHR entry.

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 Bypass System.

An ADV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, all four ADVs are required to be OPERABLE. In MODE 4, only the ADVs associated with the steam generators being relied upon for heat removal, are required to be OPERABLE.

In MODE 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one required ADV line inoperable, action must be taken to restore OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ADV lines, a non-safety grade backup in the Steam Bypass System, and MSSVs and is based on a PRA analysis and the low probability of a SGTR and LOOP event occurring during this period that would require the ADV lines.

B.1

With two ADV lines inoperable, action must be taken to restore at least one ADV line to OPERABLE status. This will result in at least three operable ADVs. Since the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 72 hour Completion Time is reasonable to repair inoperable ADV lines, based on the availability of the Steam Dump System (40% steam dump valves to the condenser) and MSSVs, and the low probability of an event occurring during this period that would require the ADV lines.

C.1

With three or more ADV lines inoperable, action must be taken to restore at least two ADV lines to OPERABLE status. This will result in at least two operable ADVs. Since the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ADV lines, based on the availability of the Steam Dump System (40% steam dump valves to the condenser) and MSSVs, and the low probability of an event occurring during this period that would require the ADV lines.

D.1 and D.2

If the ADV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon steam generator for heat removal, within 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

Plant procedures which provide a 31 day verification that the 10% ADV manual block valves are open assures that the valves have not been inadvertently closed.

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened and closed remotely using the remote manual controls and the backup air bottles. This SR ensures that the ADVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ADV 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 block valve is to isolate a failed open ADV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement. Operating experience has shown that these components are expected to pass the Surveillance when performed at the specified frequency. The Frequency is acceptable from a reliability standpoint.

SR 3.7.4.3

The function of the back-up air bottles is to assure that the ADVs will be able to be opened as required to perform a controlled cooldown of the RCS in the event of a loss of the normal air supply system. The backup air bottle system was specifically installed to allow the RCS to be cooled for a SGTR coincident with a loss of offsite power. Verification of the bottle pressure allows for timely bottle replacement and trending for leaks.

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. WCAP-11723
3. DCM S-25B, S-3B, AND S-4.

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 normal suction through valve MU-671 on the single suction line from the condensate storage tank (CST) (LCO 3.7.6, "Condensate Storage Tank (CST)") (this valve must remain open for the applicable accident analysis assumptions to be valid) 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, "Main Steam Safety Valves (MSSVs)") or atmospheric dump valves (LCO 3.7.4, "Atmospheric Dump Valves (ADVs)"). If the main condenser is available, steam may be released via the condenser steam dump valves and recirculated to the CST.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. The turbine driven pump provides 200% of the capacity of a motor driven pump.

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 feeds two steam generators, although each pump has the capability to be manually realigned to feed other steam generators. The steam turbine driven AFW pump receives steam from two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the turbine driven AFW pump.

(continued)

BASES

BACKGROUND (continued)	The turbine driven AFW pump supplies a common header capable of feeding all steam generators with Class 1E AC powered control valves. Thus, the requirement for diversity in motive power sources for the AFW System is met. The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions. The AFW System supplies sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs. The AFW System (both the one turbine-driven and two motor-driven AFW pumps) actuates automatically upon actuation of the anticipated transient without scram mitigating system actuation circuitry (AMSAC). The motor-driven pumps are additionally actuated by: (1) safety injection; (2) an associated bus transfer to the diesel generator signal; (3) a trip of both MFW pumps; or (4) steam generator water level—low-low in one of four SGs. The turbine-driven pump is additionally actuated by 12-kV bus undervoltage or steam generator low-low level in two of four SGs via ESFAS (LCO 3.3.2, “Engineered Safety Feature Actuation System (ESFAS) Instrumentation”). The AFW System is discussed in the UFSAR, Section 6.5 (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 generators 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% tolerance within 1 minute after event initiation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 AFW spillage through feedwater line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater (FWLB) or Main Steam Line Break (MSLB); and

b. Loss of normal feedwater both with and without a loss of offsite power.

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. One motor driven AFW pump would deliver to the broken MFW header at the pump maximum 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 loss of normal feedwater flow event (Ref. 1) assumes that both motor-driven AFW pumps each provide auxiliary feedwater flow to two steam generators. The limiting single failure in the analysis of this event is the failure of the turbine-driven AFW pump.

The two motor-driven pumps, supplying at least 600 gpm to four SGs, provide the minimum AFW flow required for response to a loss of normal feedwater/loss of offsite power event. This provides the design and licensing basis for response to a LONF/LOOP event.

In addition, a "better-estimate" evaluation shows that each motor driven pump can provide 100% of the feedwater flow required for removal of decay heat from the reactor. The better estimate evaluation provides a reliability basis, in accordance with NUREG-0737 (November 1980), Item II.E.1.1, for assuming availability of both motor driven pumps for accident analyses.

In addition, the minimum available AFW flow and system characteristics must be considered in the analysis of normal cooldown and small break loss of coolant accident (LOCA) due to their potential impact.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The AFW System is also designed for decay heat removal following a Steam Generator Tube Rupture (SGTR). As such the steam turbine driven AFW pump has redundant steam supplies to assure continued availability following a SGTR or MSLB event. The ESFAS automatically actuates the AFW turbine driven pump when required to ensure an adequate feedwater supply to the steam generators during loss of power. Class 1E AC power 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 decay and residual heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses and having the third AFW pump powered by a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs. To assure steam turbine driven AFW pump operability via redundant steam supplies, steam traps 104, 105 and 106 on the supply lines must be operable or bypassed to ensure adequate condensate removal and check valves MS-5166 and MS-5167 must be operable. The AFW System supply 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,

(continued)

BASES

LCO (continued)	each powered by a separated Class 1E bus, 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 steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. 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. This is because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the turbine driven AFW pump.
APPLICABILITY	In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions. In MODE 4 the AFW System may be used for heat removal via the steam generators. In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.
ACTIONS	A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW train. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW train inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance. <u>A.1</u> If the turbine driven AFW train is inoperable due to one inoperable steam supply, or if a turbine driven pump is inoperable for any reason while in MODE 3 immediately following refueling, action must be taken to restore OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. 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 due to one inoperable steam supply, the 7 day Completion Time is reasonable since there is a redundant steam supply line for the turbine driven pump and the turbine driven train is still capable of performing its specified function for most postulated events;

(continued)

BASES

ACTIONS

A.1 (continued)

b. For the inoperability of a turbine driven AFW pump while in MODE 3 immediately subsequent to a refueling, the 7 day Completion Time is reasonable due to the minimal decay heat levels in this situation; and

c. For both the inoperability of a steam supply line to the turbine driven pump due to one inoperable steam supply and an inoperable turbine driven AFW pump while in MODE 3 immediately following a refueling outage, the 7 day Completion Time is reasonable due to the availability of redundant OPERABLE motor driven AFW pumps, and due to the low probability of an event requiring the use of the turbine driven AFW pump.

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 or in accordance with the Risk Informed Completion Time Program. 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.

C.1 and C.2

With one of the required motor-driven AFW trains (pump or flow path) inoperable and the turbine-driven AFW train inoperable due to one inoperable steam supply, action must be taken to restore the affected equipment to OPERABLE status within 48 hours or in accordance with the Risk Informed Completion Time Program. Assuming no single active failures when in this condition, the accident (a FWLB or MSLB) could result in the loss of the remaining steam supply to the turbine-driven AFW pump due to the faulted SG.

A note in Condition C limits applicability to only when the remaining OPERABLE motor-driven AFW train provides feedwater to the SG with the inoperable steam supply. This Condition will only apply during the following two scenarios:

1) Motor-driven AFW pump 2 OPERABLE, motor-driven AFW pump 3 inoperable, and steam supply from SG 2 inoperable, or

2) Motor-driven AFW pump 2 inoperable, motor-driven AFW pump 3 OPERABLE, and steam supply from SG 3 inoperable.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2 (continued)

This ensures that if a FWLB were to occur affecting the OPERABLE motor driven AFW pump, the turbine-driven AFW pump would still be capable of providing AFW to two intact SGs. If a MSLB were to occur on the SG feeding the remaining OPERABLE steam supply to the turbine-driven AFW pump, the OPERABLE motor-driven AFW pump would still be capable of providing AFW to two intact SGs.

If motor-driven AFW pump 2 and the steam supply from SG 3 are inoperable, or if motor-driven AFW pump 3 and the steam supply from SG 2 are inoperable, then Condition D for two inoperable AFW pumps applies.

The 48 hour Completion Time is reasonable based on the fact that the remaining motor-driven AFW train is capable of providing 100 percent of the AFW flow requirements, and the low probability of an event occurring that would challenge the AFW system.

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

D.1 and D.2

When Required Action A.1, B.1, C.1, or C.2 cannot be completed within the required Completion Time, or if two AFW trains are inoperable in MODE 1, 2, or 3 for reasons other than Condition C, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 18 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

(continued)

BASES

ACTIONS (continued)

E.1

If all three AFW trains are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no PG&E Design Class I means for conducting a cooldown, and only limited means for conducting a cooldown with non-PG&E Design Class I 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 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.

F.1

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops-MODE 4." With one required AFW train 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.

(continued)

BASES (continued)

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. The AFW System flow paths consist of the direct flow paths from the fluid source (e.g., CST, steam generators) to the supplied PG&E Design Class I components (e.g., steam generator, turbine driven AFW pump) and portions of any branch line flow path off a direct flow path that a valve misposition could result in degradation of the system safety function. 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 which are closed and secured by a cap or blind flange (e.g., manual test, vent, and drain valves), to valves that cannot be inadvertently misaligned (e.g., check valves), or to valves in instrument or sample lines. 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.

The valves in the flowpath from the CST to the AFW pump suction are verified to be in the correct position prior to use of the AFW system for normal startup, and are subsequently controlled by a sealed valve checklist. Use of AFW for normal startups and shutdowns, and performance of the quarterly pump surveillance tests confirms that the CST flowpath to the AFW pump suction is properly aligned.

The SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i. e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

(continued)

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 OM Code (Ref 2). The ASME OM Code requires a comprehensive pump test on each AFW pump every two years. The comprehensive pump test is required to be performed at +/- 20% of pump design flow. This test confirms one point on the pump design curve and is indicative of overall performance. In addition to the comprehensive pump test, the ASME OM Code also requires a less comprehensive test to be performed at 3-month intervals for each pump. These tests are performed at recirculation flow so as to limit thermal shocking of AFW/FW piping nozzles. The ability of steam traps 104, 105, and 106 to remove condensate in the steam supplies is verified during the inservice testing of the pumps. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance.

This SR is modified by a Note indicating that the SR for the turbine-driven AFW pump should be deferred until suitable test conditions are established. This deferral is required because there is 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 generated by an auxiliary feedwater actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. Steam admission valve FCV-95 is the only valve in the AFW System that receives a direct ESFAS actuation signal, and is therefore the only valve required to be tested in accordance with this surveillance. 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 one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i. e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

(continued)

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 generated by an auxiliary feedwater actuation signal in MODES 1, 2, and 3. In MODE 4, the required pump is already operating and the 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 for the turbine-driven pump can be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. Note 2 states that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i. e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i. e., the intended safety function) continues to be maintained.

SR 3.7.5.5

Not Used.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 6.5 and Section 15.2.8.
2. ASME Code for Operation and Maintenance of Nuclear Power Plants, 2004 Edition including 2005 and 2006 Addenda
3. DCM S-3B.
4. 10 CFR 50.55a(b)(3)(vi).
5. License Amendment 215/217, January 31, 2013.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND	The CST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric dump valves if the main steam isolation valves are closed. The AFW pumps operate with a continuous recirculation to the CST. When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the condenser dump valves. The condensed steam is returned to the CST by the condensate pumps. This has the advantage of conserving condensate while minimizing releases to the environment. Because the CST is a principal components for 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 CST is designed to Seismic Category I to ensure availability of the feedwater supply. Feedwater is also available from alternate sources as described in the UFSAR. A description of the CST is found in the UFSAR, Section 9.2.6 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The CST 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). The limiting event for AFW supply, i.e., CST minimum tank volume, is based on a natural circulation cooldown due to a loss of offsite power using seismically-qualified water sources. The cooldown is performed from hot standby conditions to residual heat removal (RHR) system conditions where the RHR system can be used to remove further decay heat. The rate at which the cooldown can be performed in order to prevent voiding in the upper head depends on the operating temperature in the vessel upper head region. When the cooldown time is extended, more seismically-qualified AFW supply is required. Unit 1 operates with the upper head temperature near vessel outlet temperature (T_{hot} upper head design). Unit 2 operates with the upper head temperature near the vessel inlet temperature (T_{cold} upper head design).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

For Unit 1 with a T_{hot} upper head design, the analysis for CST minimum required storage assumes the unit is held in MODE 3 for 1 hour followed by an 8-hour cooldown to RHR entry conditions at a reduced cooldown rate of 25°F/hour. For Unit 2 with a T_{cold} upper head design, the analysis for CST minimum required storage assumes the unit is held in MODE 3 for 2 hours followed by a 4-hour cooldown to RHR entry conditions at a cooldown rate of 50°F/hour.

Other non-limiting events for AFW supply requiring condensate volume are:

1) the large feedwater line break coincident with a loss of offsite power. Single failures that also affect this event include the following:

   a. Failure of the diesel generator powering the motor driven AFW pump to the 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.

and,

2) 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 Emergency Feedwater Actuation System 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.

To satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat following a reactor trip from 102% 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 with an open flow path to 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 CST satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO	The CST volume required is for a usable volume of ≥ 200,000 gallons (51% indicated level without instrument uncertainty) for Unit 1 and ≥ 166,000 gallons (43% indicated level without instrument uncertainty) for Unit 2. The volume for Unit 1 is based on holding the unit in MODE 3 for 1 hour, followed by a natural circulation cooldown to RHR entry conditions at 25°F/hour. The volume for Unit 2 is based on holding the unit in MODE 3 for 2 hours, followed by a natural circulation cooldown to RHR entry conditions at 50°F/hour. These bases are established in Reference 4 and exceed the volume required by the accident analyses. The OPERABILITY of the CST for each unit is determined by maintaining the tank volume (equivalent indicated level) at or above the minimum required volume.
APPLICABILITY	In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the CST is required to be OPERABLE. In MODE 5 or 6, the CST is not required because the AFW System is not required.
ACTIONS	<u>A.1 and A.2</u> If the CST is not OPERABLE, the OPERABILITY of the backup supply 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 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 CST 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 CST. The seismically-qualified fire water storage tank and alternate non-seismically qualified water sources are examples of back-up water supplies available to supply water to supplement the CST volume.

(continued)

BASES

ACTIONS (continued)	<u>B.1 and B.2</u> If the CST 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 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.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.6.1</u> This SR verifies that the CST 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, Sections 9.2.6 and 9.5.1. 2. UFSAR, Chapter 6. 3. UFSAR, Chapter 15. 4. DCM S-3B.

B 3.7 PLANT SYSTEMS

B 3.7.7 Vital Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System provides a heat sink for the removal of process and operating heat from PG&E Design Class I components during a Design Basis Accident (DBA) or transient. During normal operation, the CCW System provides this function for PG&E Design Class I components, various nonessential components, and the spent fuel storage pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Auxiliary Saltwater (ASW) System, and thus to the environment.

The CCW system consists of three CCW pumps powered by separate Class 1E buses, two CCW heat exchangers, and a two chamber CCW surge tank. The piping system consists of three parallel headers. The headers extend from the outlet of the heat exchangers through the header heat loads to the suction of the CCW pumps. The two PG&E Design Class I headers serve redundant ESF loads and the non-redundant post-LOCA sample coolers (header A, only). A third, non-PG&E Design Class I header serves non-PG&E Design Class I equipment. Each of the headers are separable from the others to mitigate a passive single failure during post-LOCA long term cooling. The divided surge tank is connected to the PG&E Design Class I header return piping and is sized to meet system leakage requirements and maintain adequate NPSH on system pumps.

The CCW system is hydraulically balanced to ensure that sufficient cooling water is delivered to ESF loads on the PG&E Design Class I loops and to limit heat input to the system during a DBA.

The CCW system is designed to perform its safety function with a single active failure of any component during the short term recovery period. All three pumps are automatically started on receipt of a safety injection signal, and flow to the miscellaneous service loop is automatically shut off on hi-hi containment pressure.

With the PG&E Design Class I loops separated during the long term recovery period, the CCW system is designed to perform its safety function with either a single active or passive failure. 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 PG&E Design Class I function of the CCW System is the removal of accident generated containment heat via the containment fan cooling units (CFCUs) and removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. Decay heat removal may be during a normal or post accident cooldown and shutdown.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The design basis of the CCW System is for one PG&E Design Class I CCW loop to remove the post DBA heat load from the containment, without exceeding a CCW supply temperature of 120°F with an allowable transient not to exceed 140°F for more than 6 hours (Ref. 1). The CCW system is designed to provide sufficient heat removal for normal and post accident ESF heat loads without overheating. The CCW system and ASW system are essentially considered a single heat removal system for the purpose of assessing the ability to sustain either a single active or passive failure and still perform design basis heat removal. Only one ASW pump and one CCW heat exchanger is required, as assumed in the safety analysis, to provide sufficient heat removal from containment to mitigate a DBA. However, to ensure maximum heat removal capability, operators are instructed to place the second CCW heat exchanger in service early in the emergency operating procedures. The CCW System also functions to cool the unit from RHR entry conditions (T_{ave} < 350°F), to MODE 5 (T_{ave}< 200°F), during normal and post accident operations. The time required to cool from 350°F to 200°F is a function of the number of CCW heat exchangers, RHR heat exchangers, CFCUs and miscellaneous loads in service. In the event that CCW system leakage occurs and system makeup is not available, the surge tank volume provides a minimum of 20 minutes, based on a non-mechanistic leakage rate of 200 gpm, for operators to locate and isolate the leak or realign the CCW system into two separate PG&E Design Class I loops before the system becomes impaired due to water loss. The CCW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	In the event of a DBA, one PG&E Design Class I CCW loop is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two PG&E Design Class I loops of CCW must be OPERABLE. At least one CCW loop will operate assuming the worst case single active failure occurs coincident with a loss of offsite power. To meet the LCO on CCW loops, PG&E Design Class I headers A and B, both CCW heat exchangers, the surge tank, and all three CCW pumps must be operable.

(continued)

BASES

LCO (continued)	A PG&E Design Class I CCW loop is considered OPERABLE when: a. Two CCW pumps, one CCW heat exchanger, one PG&E Design Class I CCW header and the surge tank are OPERABLE; and b. The associated piping, valves, and instrumentation and controls required to perform the PG&E Design Class I function are OPERABLE. The isolation of CCW from other components or systems may render those components or systems inoperable but does not affect the OPERABILITY of the CCW System, except for isolation of CCW to the CFCUs. Isolation of CCW to the CFCUs could potentially affect the flow balance and requires evaluation to ensure continued operability. Split loop alignment of the CCW system during normal operation requires Condition A to be entered because the CCW system cannot tolerate a single failure in this configuration.
APPLICABILITY	In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be prepared to perform its principal PG&E Design Class I function of removal of accident generated containment heat via the CFCUs and removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. In MODE 5 or 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.
ACTIONS	<u>A.1</u> Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops-MODE 4," be entered if an inoperable PG&E Design Class I CCW loop results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. If one PG&E Design Class I CCW loop is inoperable, action must be taken to restore two PG&E Design Class I CCW loops to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE PG&E Design Class I CCW loop is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the overall heat transfer capability of ultimate heat sink system, operator action, and the low probability of a DBA occurring during this period. Split loop alignment of the CCW system during normal operation requires Condition A to be entered because the CCW system cannot tolerate a single failure in this configuration.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the PG&E Design Class I CCW loop cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System. A possible exception to this note, is isolation of CCW to the CFCUs. Isolation of CCW to the CFCUs could potentially affect the flow balance and requires evaluation to ensure continued operability.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. The CCW flow path consists of the direct flow path servicing the PG&E Design Class I equipment (e.g., ECCS pump coolers, CFCUs, RHR heat exchanger) and portions of any branch line flow path off the direct flow path that a valve misposition could result in degradation of the system safety function. 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 which are closed and secured by a cap or blind flange (e.g., manual test, vent, and drain valves), to valves that cannot be inadvertently misaligned (e.g., check valves), or to valves in instrument or sample lines. 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 3.7.7.2

This SR verifies proper automatic operation of the CCW valves on an actual or simulated Phase A or Phase B containment isolation actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.7.3 This SR verifies proper automatic operation of the CCW pumps on an actual or simulated safety injection or loss of offsite power (4kV auto transfer) actuation signal. This surveillance requirement applies to the SIS auto-start and the 4kV auto-transfer automatic starts only. 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. 2. UFSAR, Section 6.2. 3. WCAP-14282, Revision 1, “Evaluation of Peak CCW Temperature Scenarios for Diablo Canyon Units 1 and 2,” dated December 1997. 4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010

B 3.7 PLANT SYSTEMS

B 3.7.8 Auxiliary Saltwater System (ASW)

BASES

BACKGROUND	The ASW system provides a heat sink from the Pacific Ocean for the removal of process and operating heat from the CCW system. The CCW system then provides cooling to PG&E Design Class I components during all modes of operation, including a DBA, and also to various non-PG&E Design Class I components during normal operation and shutdown. The ASW consists of two, 100% capacity, PG&E Design Class I, cooling water trains. Each train consists of one 100% capacity pump, one component cooling water (CCW) heat exchanger, piping, valving, and instrumentation. The pumps are automatically started upon receipt of a safety injection signal or 4kV automatic transfer. Normal configuration is for one train operation with the second pump cross-tied in stand-by and the second heat exchanger valved out-of-service except when the UHS temperature is 64°F or higher; therefore no valve realignment occurs with a safety injection signal. Manual and remote manual system realignment provides for utilization of the second CCW heat exchanger, for use of the standby pump on the same unit, for cross-tying the standby ASW pump from opposite unit, and for train separation for long term cooling. The ASW unit cross-tie valve (FCV-601) allows one ASW pump on one unit to supply the CCW heat exchanger(s) on the other unit. In the event of a total loss of ASW in one unit, the capability to cross-tie units ensures the availability of sufficient redundant cooling capacity for the affected unit. If the unit cross-tie capability were used, the unit with no operable ASW train would enter LCO 3.0.3, and the unit from which ASW was being provided would be in a 72-hour action with the cross-tie then declared inoperable. FCV-601 is controlled by ECG 17.1. Additional information about the design and operation of the ASW system, is presented in the UFSAR, Section 9.2.7 (Ref. 1). The principal PG&E Design Class I function of the ASW system is the removal of decay heat from the reactor via the PG&E Design Class I CCW System.
APPLICABLE SAFETY ANALYSES	The design basis of the ASW system is for one ASW train, in conjunction with the CCW System and the containment cooling systems, to remove accident generated and core decay heat following a design basis LOCA as discussed in the UFSAR, Section 6.2 (Ref. 2). The ASW system can be re-configured to maintain the CCW temperature to within its design bases limits. The ASW system is designed to perform its function with a single failure of any active

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	component, with or without the loss of offsite power. This assumes a maximum ASW temperature of 64°F occurring simultaneously with maximum heat loads on the system. The ASW system, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of ASW pumps, CCW heat exchangers, and RHR heat exchangers that are operating. One ASW train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. However, in the split-train configuration during post-accident operation, operator action may be required to realign the ASW and CCW systems to prevent loss of all cooling to containment and PG&E Design Class 1 systems following specific active failure scenarios. The ASW system satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two ASW trains 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. An ASW train is considered OPERABLE during MODES 1, 2, 3, and 4 when: a. The pump is OPERABLE; and b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the PG&E Design Class I function are OPERABLE. This requires that at least one vacuum relief valve be OPERABLE. Each ASW train has a vacuum relief system consisting of two vacuum relief valves (check valves) which function to prevent water hammer in the system piping during an ASW pump trip and restart transient. Check valves are passive components and, unless otherwise specified, are not considered in meeting the single failure criterion. The second vacuum relief valve on each header ensures reliability of the function. If both vacuum relief valves on a single header are inoperable, water hammer during an ASW pump trip and restart transient could affect both ASW trains unless the ASW header cross-tie valve is closed and the ASW pump breaker or dc control power switch is opened for the affected ASW train, precluding the potential for water hammer in the train. Refer to ECG 17.4, "ASW Pump Discharge Vacuum Relief Valves."

(continued)

BASES

LCO (continued)

Both cross-tie valves FCV-495 and FCV-496 are required to be open to support single active failure criteria. The valves may be closed in post-accident long-term phase to support passive failure criteria, if system integrity is a concern. With one or both ASW trains in service with the cross-tie valves closed, a single active failure could result in a significant reduction or loss of heat removal capability. With both ASW trains in service, approximately one-half of the total CCW flow is routed through each CCW heat exchanger. In the event of a postulated ASW pump failure in this configuration, with the cross-tie valves closed, only one ASW pump will be operating and providing heat removal to one-half of the total CCW flow via its associated in-service CCW heat exchanger. In this situation, the ASWS heat removal capability is limited and may not meet the requirements of the system to maintain the CCW supply temperature within its design limits.

c. The associated pump vault drain check valve is OPERABLE. The ASW pump vault check valves prevent flooding of the ASW pump vaults during design flood events.

APPLICABILITY

In MODES 1, 2, 3, and 4, the ASW system is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the ASW system and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the ASW system are determined by the systems it supports.

(continued)

BASES (continued)

ACTIONS

A.1

If one ASW train is inoperable, action must be taken to restore OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE ASW train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE ASW train could result in loss of ASW system function. The Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops-MODE 4," should be entered if an inoperable ASW train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

The 72-hour Completion Time is modified by a Note that allows a one-time Completion Time of 144 hours for ASW pump 2-2, for Unit 2 cycle 24 to support emergent replacement of the ASW pump 2-2 motor. The one-time Completion Time of 144 hours is reasonable considering the capabilities of the other ASW Pump 2-1 to perform the heat removal function, the cross-tie capabilities of ASW from Unit 1, the low probability of a design basis accident occurring during this period, and the one-time use of a 144-hour Completion Time.

(continued)

BASES (continued)

ACTIONS

B.1 and B.2

If the ASW train cannot be restored to OPERABLE status within the associated Completion Times, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

(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.
SURVEILLANCE REQUIREMENTS	SR 3.7.8.1 Verifying the correct alignment for manual and power operated valves in the ASW system flow path provides assurance that the proper flow paths exist for ASW system operation. The ASW system flow path consists of the direct flow path servicing the PG&E Design Class I equipment (e.g., CCW heat exchanger) and portions of any branch line flow path off the direct flow path that a valve misposition could result in degradation of the system safety function. 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 also does not apply to valves which are closed and secured by a cap or blind flange (e.g., manual test, vent, and drain valves), to valves that cannot be inadvertently misaligned (e.g., check valves), or to valves in instrument or sample lines. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.2

This SR verifies proper remote manual full stroke operation of the ASW valves. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 92 day Frequency is based on the IST program frequency and is consistent with the ASME O&M Code testing requirements, and ensures the ability to correctly align the valves. Operating experience has shown that these components usually pass the Surveillance when performed at the 92 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.3

This SR verifies proper automatic operation of the ASW pumps on an actual or simulated PG&E Design Class I actuation signal. The ASW is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. This surveillance requirement applies to the SIS auto-start and the 4kV auto transfer automatic starts only. 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 9.2.7.
2. UFSAR, Section 6.2.
3. NRC Generic Letter 91-13, "Request for Information Related to the Resolution of Generic Issue 130, 'Essential Service Water System Failures at Multi-unit Sites,' Pursuant to 10 CFR 50.54 (F)," dated September 19, 1991.
4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND	The UHS provides a heat sink for transferring heat from PG&E Design Class I components during a transient or accident, as well as PG&E Design Class I and non-PG&E Design Class I heat loads during normal operation. This is done by utilizing the Pacific Ocean, the Auxiliary Saltwater System (ASW) and the Component Cooling Water (CCW) System. The UHS is common to both units and has been defined as the Pacific Ocean. The principal functions of the UHS are dissipation of heat during normal operation, dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident. The basic performance requirements are that a 30 day supply of water be available, and that the design basis temperatures of PG&E Design Class I equipment not be exceeded. To ensure UHS availability, ASW components located within the projected sea wave zone are designed to operate during extreme ocean levels for a short duration (for example, tsunami run up and draw down conditions) per Reference 2. To maintain adequate cooling for PG&E Design Class I equipment, operational limits are established based on ocean supply temperature. 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 and containment following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation. The Pacific Ocean as a single water source for the Ultimate Heat Sink will provide in excess of 30 days of cooling water during normal and emergency shutdown conditions as required by AEC Safety Guide 27 (Ref. 3). The UHS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The UHS is required to be OPERABLE and is considered OPERABLE if it is at or below the maximum temperature that would allow the ASW to operate for at least 30 days following the DBA without exceeding the maximum design temperature of the CCW system. To meet this condition, the UHS temperature should not exceed 64°F unless two CCW heat exchangers are in service during normal unit operation. With two heat exchangers in service, operation with elevated UHS temperatures as high as 70°F is acceptable.

(continued)

BASES (continued)

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	<u>A.1</u> If the UHS is inoperable (i.e., inlet water temperature > 64°F), the compensatory action of placing a second CCW heat exchanger in service must be performed within 8 hours. This action provides assurance that the ASW system and the CCW system can operate within its temperature limit. With two heat exchangers in service, operation with elevated UHS temperatures as high as 70°F is acceptable. The 8 hour Completion Time is reasonable based on the low probability of an accident occurring during the 8 hours that the temperature is > 64°F without two CCW heat exchangers in service and the time required to reasonably complete the Required Action. <u>B.1 and B.2</u> If the second heat exchanger cannot be placed in service within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS	B.1 and B.2 (continued) Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 Not Used. SR 3.7.9.2 This SR verifies that adequate long term (30 day) cooling can be maintained. The 24, 12 and 2 hour surveillance Frequencies are based on operating experience related to trending of the temperature variations during the applicable MODES. This SR verifies the temperature of the UHS so that appropriate actions can be taken to assure that the ASW system can continue to assure that the CCW system will not exceed its design temperature profile.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	<u>SR 3.7.9.3</u> Not Used. <u>SR 3.7.9.4</u> Not Used.
REFERENCES	1. UFSAR, Section 9.2.5. 2. UFSAR, Sections 2.4.12.5 and 2.4.12.6 3. AEC Safety Guide 27. 4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Ventilation System (CRVS)

BASES

BACKGROUND

The CRVS provides a protected environment from which occupants can control the units from the common control room following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The CRVS consists of two independent, redundant trains that recirculate and filter the air in the control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air (one train from each unit). Each CRVS train consists of a heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and one pressurization supply fan, one filter booster fan, and one main supply fan. Ductwork, valves or dampers, doors, barriers, and instrumentation also form part of the system.

The CRVS is an emergency system, parts of which may also operate during normal unit operations. Upon receipt of an actuating signal, the normal air supply to the CRE is isolated, and the stream of outside ventilation air from the pressurization system and recirculated control room air is passed through the system filter. The pressurization system draws outside air from either the north end or the south end of the turbine building based upon the wind direction or the absence of releases at the inlet. The prefilters remove any large particles in the air, to prevent excessive loading of the HEPA filters and charcoal adsorbers. The heaters are important to the effectiveness of the charcoal adsorbers but are not required for CRVS operability.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of DBA consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

(continued)

BASES

BACKGROUND (continued)

Manual or automatic actuation of the CRVS places the system in one of three states; 1) pressurization (Mode 4), 2) recirculation (Mode 3), or 3) smoke removal (Mode 2). Mode 4 is the only required mode for the CRVs to be considered OPERABLE. The other modes of operation are useful for certain emergency situations, such as control room smoke removal; but they are not required for CRVS OPERABILITY. Actuation of the system to the recirculation mode closes the unfiltered outside air intake and unfiltered exhaust dampers, and aligns the system for recirculation of the air within the CRE through the redundant trains of HEPA and the charcoal filters. The pressurization mode also initiates pressurization and filtered ventilation of the air supply to the CRE.

Outside air is filtered, diluted via pressure equalization with air from the mechanical equipment room, and added to the air being recirculated from the CRE. Pressurization of the CRE minimizes infiltration of unfiltered air through the CRE boundary from all the surrounding areas adjacent to the CRE boundary.

The actions taken in the manual actuation of the recirculation mode are the same, except that the signal switches the CRVS to an isolation alignment to minimize any outside air from entering the CRE through the CRE boundary.

To monitor the status of the booster fan(s) small plastic streamers are installed on the exhaust duct grates. These exhaust ducts are located in the back of the control room in the ceiling and are used to take suction on the control room atmosphere. These streamers will hang down when the booster fan(s) are not operating. Therefore if a booster fan is in operation the streamers will be "up". This will permit the operators to diagnose a problem with the booster fan or with the booster fan supply damper.

The pressurization mode is the only automatically actuated mode change since bulk chlorine gas is no longer kept onsite and the chlorine monitors which previously initiated the recirculation mode have been de-activated.

The air entering the CRE is continuously monitored by radiation detectors. One detector output above the setpoint will cause actuation of the pressurization mode.

A single train CRVS will pressurize the CRE to about 0.125 inches water gauge relative to external areas adjacent to the CRE boundary. The CRVS operation in maintaining the CRE habitable is discussed in the UFSAR, Section 9.4.1 (Ref. 1).

(continued)

BASES

BACKGROUND (continued)	Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across the other filter train. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. The CRVS is designed in accordance with Seismic Category I requirements. The CRVS is designed to maintain a habitable environment in the CRE for the duration of the most severe Design Basis Accident (DBA) without exceeding a 5 rem TEDE dose.
APPLICABLE SAFETY ANALYSES	The CRVS components are arranged in redundant, PG&E Design Class I ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The CRVS provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE occupant dose analyses for the most limiting design basis accident, fission product release presented in the UFSAR, Chapter 15 (Ref. 2). There are no offsite or onsite hazardous chemicals that would pose a credible threat to control room habitability. Consequently, engineered controls for the control room are not required to ensure habitability against a hazardous chemical threat. The amount of CRE unfiltered inleakage is not incorporated into PG&E's hazardous chemical assessment. The evaluation of a smoke challenge demonstrated that smoke will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 1). The assessment verified that a fire or smoke event anywhere within the plant would not simultaneously render the Hot Shutdown Panel (HSP) and the CRE uninhabitable, nor would it prevent access from the CRE to the HSP in the event remote shutdown is required. No CRVS automatic actuation is required for hazardous chemical releases or smoke and no Surveillance Requirements are required to verify operability in cases of hazardous chemicals or smoke.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The worst case single active failure of a component of the CRVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. The CRVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant CRVS trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. The redundant train means a second train from the other unit (Ref. 5). Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem TEDE to the CRE occupants in the event of a large radioactive release.
Each CRVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A CRVS train is OPERABLE when the associated:

a. main supply fan (one), filter booster fan (one) and pressurization fan (one) are OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In order for the CRVS trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs. In the event of an inoperable CRE boundary in MODES 1, 2, 3, or 4, mitigating actions are required to ensure CRE occupants are protected from hazardous chemicals and smoke.

DCPP does not have CRVS automatic actuation for hazardous chemicals or smoke. Current practices at DCPP do not utilize chemicals in sufficient quantity to present a chemical hazard to the control room. Smoke is not considered in the DCPP safety analyses. Therefore, there are no specific limits at DCPP for hazardous chemicals or smoke.

(continued)

LCO (continued)	The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should consist of stationing a dedicated individual at the opening who is in continuous communication with the operator in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated and will be trained to perform that function.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and during movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) the CRVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA or the release from the rupture of an outside waste gas tank.

During movement of recently irradiated fuel assemblies, the CRVS must be OPERABLE to cope with the release from a fuel handling accident involving handling recently irradiated fuel.

CRVS OPERABILITY requires that for MODE 5 and 6 and during movement of recently irradiated fuel assemblies in either unit, when there is only one OPERABLE train of CRVS, the OPERABLE CRVS train must be capable of being powered from an OPERABLE diesel generator that is directly associated with the bus which is energizing the OPERABLE CRVS train. This is an exception to LCO 3.0.6.

ACTIONS

The ACTIONS are modified by a NOTE that states that ACTIONS apply simultaneously to both units. The CRVS is common to both units.

A.1

When one CRVS train is inoperable for reasons other than an inoperable CRE boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRVS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CRVS train could result in loss of CRVS 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 train to provide the required capability.

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

The CRE boundary is inoperable if unfiltered inleakage past the CRE boundary can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE).

In the event of an inoperable CRE boundary in MODES 1, 2, 3, or 4, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from potential smoke and chemical hazards.

(continued)

BASES

ACTIONS

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

These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. Actions must be taken to restore the CRE boundary to OPEARABLE status within 90 days. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair and test most problems with the CRE boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable CRVS train or the CRE boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE in which the overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 14). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 14, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

(continued)

BASES

ACTIONS

C.1 and C.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.

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

In MODE 5 or 6, or during movement of recently irradiated fuel assemblies, if the inoperable CRVS train cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE CRVS train in the pressurization mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected. If only one CRVS train is OPERABLE, the OPERABLE train must be capable of being powered from an OPERABLE diesel generator that is directly associated with the bus which is energizing the OPERABLE CRVS train. The power requirements for the one OPERABLE CRVS train assures that the ventilation function will not be lost during a fuel handling accident with a subsequent loss of off-site power. This is an exception to LCO 3.0.6.

An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

(continued)

BASES

ACTIONS (continued)

E.1

In MODE 5 or 6, or during movement of recently irradiated fuel assemblies, with two CRVS trains inoperable or with one or more CRVS trains inoperable due to an inoperable CRVS boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

F.1

If both CRVS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than an inoperable CRE boundary (i.e., Condition B), the CRVS 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

Once actuated due to a fuel handling accident the CRVS must be protected against a single failure. This protection, although not required for immediate accident response, is assured by requiring that a backup power supply be provided as described above in Applicability. This back up is assured via the performance of surveillances that verify the ability to transfer power supplies.

The 31 day procedural verification of the separate Class 1E power supplies for the redundant fans assures system reliability.

SR 3.7.10.1

Standby systems should be checked periodically for ≥ 15 minutes to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train once every month, by initiating, from the control room, flow through the HEPA filter and charcoal adsorber using either redundant set of booster and pressurization supply fans, provides an adequate check of this system. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.10.2

This SR assures that the emergency power alignment is appropriate for the operating conditions of the plant. With the power supply options available it is appropriate to verify that the redundant fans for each train are aligned to receive power from separate OPERABLE Class 1E buses.

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 (continued)

SR 3.7.10.3

This SR verifies that the required CRVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CRVS filter tests are in accordance with ANSI N510-1980 (Ref. 3). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.4

This SR verifies that each CRVS train automatically starts and operates in the pressurization mode on an actual or simulated actuation signal generated from a Phase "A" Isolation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.10.5

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program. Any changes to the most limiting configuration of the CRVS testing alignment for determining unfiltered air inleakage past the CRE boundary into the CRE must be made using a conservative decision making process (References 11-13).

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. For DCPP, there is no CRVS automatic actuation for hazardous chemical releases or smoke and there are no CRVS Surveillance Requirements that verify operability in cases of hazardous chemicals or smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.5 (continued)

Compensatory measures are discussed in Regulatory Guide 1.196 (Ref. 8), Section C.2.7.3, which endorses, with exceptions, NEI 99-03 (Ref. 9), Rev. 0, Section 8.4 and Appendix F. These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 10). Options for restoring the CRE boundary to OPERABLE status include: (a) changing the licensing basis DBA consequence analysis; or (b) repairing the CRE boundary; or a combination of both (a) and (b) options. Restoration of OPERABILITY via compensatory measures is restricted to only (a) and/or (b). Depending upon the complexity of the problem, it is prudent to proactively discuss the proposed compensatory measures with the NRC TS Branch to verify the compensatory measures satisfy the intent of an OPERABLE CRE boundary before declaring OPERABILITY (References 11-13).

Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

(continued)

BASES (continued)

REFERENCES

1. UFSAR Sections 9.4 and 9.5.
2. UFSAR, Chapter 15.
3. ANSI N510-1980.
4. NUREG-0800, Section 6.4, Rev. 2, July 1981.
5. DCM S-23F.
6. License Amendment 119/117, April 14, 1997.
7. License Amendment 184/186, January 3, 2006.
8. Regulatory Guide 1.196.
9. NEI 99-03, “Control Room Habitability Assessment,” June 2001.
10. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability" (ADAMS Accession No. ML040300694)
11. SAPN 50526526, "Failure to Restore CRE to Operable : ACE Report"
12. Task Interface Agreement from NRC dated November 20, 2012, "Final Response to Task Interface Agreement 2012-08, Diablo Canyon Power Plant, Unit 1 and 2 – Request Office of Nuclear Reactor Regulation's Review of Operability Issues Associated with Technical Specification 3.7.10, "Control Room Ventilation System"".
13. Diablo Canyon Power Plant – NRC Integrated Inspection Report 05000275/2012005 and 05000323/2012005, dated February 12, 2013
14. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010

B 3.7 PLANT SYSTEMS

B 3.7.11 Not Used

B 3.7 PLANT SYSTEMS

B 3.7.12 AUXILIARY BUILDING VENTILATION SYSTEM (ABVS)

BASES

BACKGROUND

The ABVS filters air from the area of the active ECCS components during the recirculation phase of a loss of coolant accident (LOCA). The ABVS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the ECCS pump room area, if one of the pumps is operating, and the auxiliary building.

The ABVS consists of two trains. Each train is powered by a separate Class 1E bus and consists of a supply fan and an exhaust fan. These trains both provide airflow through a single roughing and HEPA filter which is common to both trains for normal operations; and a single roughing filter, HEPA filter, and charcoal adsorber bank and a single manually initiated heater are common to both trains for emergency operations. Ductwork, valves or dampers, and instrumentation also form part of the system. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. Dampers that permit air circulation are arranged in parallel pairs so that the failure of one damper to open will not result in a restriction in air flow.

The ABVS has several modes of operation. These modes include: (1) Building Only; (2) Building and Safeguards; and (3) Safeguards only. In the Building Only mode of operation, the ABVS provides ventilation flow to all parts of the auxiliary building except for the ECCS pump rooms, but does take suction from the ECCS rooms. If any ECCS pump is started, the ABVS will automatically re-align to the Building and Safeguards mode of operation. In the Building and Safeguards mode of operation, ventilation is provided to the entire auxiliary building, including the ECCS pump rooms. In the Safeguards Only mode of operation, only the ECCS pump rooms and the lower reaches of the auxiliary building are provided with ventilation. If a SI signal is generated, the system will automatically realign such that all exhaust flow from the ECCS pump rooms passes through the common HEPA filter/charcoal adsorber bank prior to being exhausted to atmosphere. Whenever an SI signal is generated, the operator can manually energize the heater from the control room. A supply fan and its supply duct dampers are required to be in their correct position to ensure the air flow is directed to ECCS pump rooms, since supply ventilation is required to maintain temperatures of the operating ECCS motors within allowable temperature limits.

(continued)

BASES

BACKGROUND (continued)	The ABVS is discussed in the UFSAR, Sections 9.4 2, and 15.5 (Refs. 1, and 2, respectively) since it may be used for normal, as well as post accident, ventilation and atmospheric cleanup functions. The primary purpose of the single manually initiated heater is to maintain the relative humidity at an acceptable level, consistent with iodine removal efficiencies per ASTM D 3803-1989 (Ref. 3). There is no redundant heater since the failure of the charcoal adsorber and heater train would constitute a second failure in addition to the RHR pump seal failure assumed in conjunction with a LOCA (Ref.7). The heaters are not required for ABVS operability.
APPLICABLE SAFETY ANALYSES	The design basis of the ABVS is established by the large break LOCA. The system evaluation assumes a passive failure of the ECCS outside containment, such as an RHR pump seal failure, during the recirculation mode. In such a case, the system limits radioactive release to within the 10 CFR 50.67 (Ref. 5) limits. The analysis of the effects and consequences of a large break LOCA is presented in Reference 2. The ABVS also functions, following a 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 ventilation flow is also required to maintain the temperatures of the operating ECCS motors within allowable limits. The ventilation function has been designed for single failure and the system will continue to function to provide its ECCS motor cooling function. Two types of system failures are considered in the accident analysis for radiation release: complete loss of function of one train, and excessive RHR pump seal LEAKAGE. Either type of failure may result in a lower efficiency of removal for any gaseous and particulate activity released to the ECCS pump rooms following a LOCA. The ABVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two trains of the ABVS are required to be OPERABLE to ensure that at least one is available, assuming that a single failure disables the other train coincident with loss of offsite power. Total system failure could result in the atmospheric release from the ECCS pump room exceeding 10 CFR 50.67 limits in the event of a Design Basis Accident (DBA). ABVS is considered OPERABLE when the individual components necessary to maintain the ECCS pump room filtration and temperature are OPERABLE in both trains.

(continued)

BASES

LCO (continued)

An ABVS train is considered OPERABLE when its associated:

a. Supply and exhaust fans are OPERABLE;

b. The common roughing filter, HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE and air circulation can be maintained.

For ABVS series dampers that have a safety function configuration of closed, the ABVS train is considered OPERABLE when one series damper is closed and secured (i.e., motive force removed from damper) and the closed damper position is verified closed to verify it is capable of performing its isolation function.

For ABVS parallel dampers that have a safety function configuration of open, the ABVS train is considered OPERABLE when one parallel damper is open and secured (i.e., motive force removed from damper) and the open damper position is verified open to verify it is capable of permitting air recirculation.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the ABVS is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS.

In MODE 5 or 6, the ABVS is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

ACTIONS

A.1

With the common HEPA filter and/or charcoal adsorber bank inoperable, the cooling function of the ABVS for ECCS motors is maintained; however, the filtration system function is lost. Since the entire function of the system is not lost, a 24 hour completion time is provided to restore the filters.

The 24 hour completion time is acceptable because it is a common filter system and the Completion Time is shorter than the ECCS Completion Time. The 24 hour Completion Time is based on the low probability of a DBA occurring during this time period.

B.1

With one ABVS train inoperable, action must be taken to restore OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the ABVS function.

The 7 day Completion Time is appropriate because the risk contribution is less than that for the ECCS (72 hour Completion Time). The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

Concurrent failure of two ABVS trains would result in the loss of both filtration and cooling capability; therefore, LCO 3.0.3 must be entered immediately.

C.1 and C.2

If the ABVS train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 8). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 8, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Each ABVS train should be checked periodically to ensure that it functions properly. As the environment and normal operating conditions on this system are not severe, testing each train with flow through both the HEPA filter and charcoal adsorber bank once a month provides an adequate check on this system. Both ABVS trains shall be operated long enough (≥ 15 minutes) to verify all components are operating correctly. Monthly verification of the separate OPERABLE Class 1E power supplies for the exhaust fans assures system redundancy. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.2

This SR verifies that the required ABVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The ABVS filter tests are in accordance with References 3 and 4. The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.12.3

The SR is modified by a Note, which limits the applicability of this SR when the ABVS is already in its safety function configuration and is verified to be capable of providing that function. The intent of this change is only to address this specific condition and the SR is considered applicable and must be met whenever the ABVS is not in that configuration.

This SR verifies that each ABVS train actuates on an actual or simulated actuation signal by verifying that the system aligns to exhaust through the common HEPA filter and charcoal adsorber and that flow is established through the HEPA and charcoal adsorber (Ref. 3 and 4). The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.4

Not Used.

SR 3.7.12.5

Not Used.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.7.12.6 This SR verifies the leak tightness of dampers that isolate flow to the normally operating filter train. This SR assures that the flow from the auxiliary building passes through the HEPA filter and charcoal adsorber unit when the ABVS Buildings and Safeguards or Safeguards Only modes have been actuated coincident with an SI. 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 9.4.2 2. UFSAR, Section 15.5 3. ASTM D 3803-1989 4. ANSI N510-1980 5. 10 CFR 50.67 6. NUREG-0800, Section 6.5.1, Rev. 2, July 1981 7. DCM S-23B, "Auxiliary Building Ventilation System" 8. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Handling Building Ventilation System (FHBVS)

BASES

BACKGROUND	The FHBVS filters airborne radioactive particulates and radioactive iodine from the area of the fuel pool following a fuel handling accident. The FHBVS provides environmental control of temperature and humidity in the fuel pool area and for the AFW pump motors. The ventilation for the AFW pump motors is to provide cooling flow for EQ considerations, i.e., motor longevity. The ventilation is not required to function during an accident or for the few hours required to reach RHR conditions during a natural circulation cooldown. The FHBVS consists of two independent and redundant trains. Each train consists of, an exhaust prefilter, high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and an exhaust fan. A third non-PG&E Design Class I exhaust fan is used for normal operation and has only a prefilter and a HEPA filter. Ductwork, valves or dampers, and instrumentation also form part of the system. The system initiates filtered ventilation of the fuel handling building following receipt of a high radiation signal or loss of the normal exhaust fan E-4. The FHBVS is a standby system, parts of which may also be operated during normal plant operations. Upon receipt of the actuating signal, normal air discharge from the fuel handling building is isolated and the normal exhaust fan shuts down and the PG&E Design Class I exhaust fans start and the stream of ventilation air discharges through the system filter trains. The prefilter removes any large particles in the air, to prevent excessive loading of the HEPA filter and charcoal adsorber. The FHBVS is discussed in the UFSAR, Sections 9.4.4 and 15.5 (Refs. 1, and 2, respectively) because it may be used for normal, as well as post (fuel handling) accident, atmospheric cleanup functions.
APPLICABLE SAFETY ANALYSES	The FHBVS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident (FHA) involving the handling of non-recently irradiated fuel (i.e., an irradiated fuel assembly that is being moved 72 hours after shutdown). The analysis of the FHA, given in Reference 2, assumes that all fuel rods in an assembly are damaged. The DBA is assumed to occur 72 hours after shutdown. The FHA radiological consequences analysis does not rely on either building integrity or the FHA radiological consequence mitigating systems (i.e., no credit is taken for the functionality of either FHBVS train's activated charcoal adsorber section).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The assumptions used in the analysis are consistent with Regulatory Guide 1.183 (Ref. 3).The FHBVS is only required to be OPERABLE during the handling of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) in the fuel handling building (Ref. 12). The FHBVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two independent and redundant trains of the FHBVS are required to be OPERABLE to ensure that at least one train is available, assuming a single failure that disables the other train. Loss of offsite power is not considered concurrent with a fuel handling accident. This requires that when two trains of the FHBVS are OPERABLE, at least one train of the FHBVS must be capable of being powered from an OPERABLE diesel generator that is directly associated with the bus which energizes the FHBVS train. When only one train is OPERABLE, an OPERABLE diesel generator must be directly associated with the bus which energizes that one OPERABLE FHBVS train. Total system failure could result in the atmospheric release from the fuel handling building exceeding the 10 CFR 50.67 (Ref. 4) limits in the event of a fuel handling accident involving the handling of recently irradiated fuel. The FHBVS is considered OPERABLE when the individual components necessary to control releases from fuel handling building are OPERABLE in both trains. An FHBVS train is considered OPERABLE when its associated: a. Exhaust fan is OPERABLE; b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

(continued)

BASES (continued)

APPLICABILITY	In MODE 1, 2, 3, 4, 5 or 6, the FHBVS is not required to be OPERABLE since it provides no safety function associated with these MODES of operation. During movement of recently irradiated fuel in the fuel handling building, the FHBVS is required to be OPERABLE to alleviate the consequences of a fuel handling accident. To reduce doses even further below that due to natural decay and manage the risk, consistent with 10 CFR 50.65 and NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants”, at least one of the two safeguard FHBVS exhaust fans, capable of being powered from an available diesel generator that is a Class 1E power source, shall be available during movement of non-recently irradiated fuel in the fuel handling building to provide the filtration capability in the event of a fuel handling accident. (References 10 and 11)
ACTIONS	The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies 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. <u>A.1</u> With one FHBVS train inoperable, action must be taken to restore OPERABLE status immediately. <u>B.1 and B.2</u> When Required Action A.1 cannot be completed within the required Completion Time, during movement of recently irradiated fuel assemblies in the fuel building, the OPERABLE FHBVS train must be started immediately and verify that it has an OPERABLE emergency power source and is discharging through its HEPA filter and charcoal adsorber. Or suspend movement of recently irradiated fuel assemblies in the fuel handling building. The suspension of movement of fuel assemblies does not preclude movement of assemblies to a safe position. This action ensures that the remaining train is OPERABLE, that no undetected failures preventing system operation will occur, and that any active failure will be readily detected. If the system is not placed in operation, this action requires suspension of recently irradiated fuel movement, which precludes a fuel handling accident involving handling of recently irradiated fuel. This does not preclude the movement of fuel assemblies to a safe position.

(continued)

BASES

ACTIONS (continued)

C.1

When two trains of the FHBVS are inoperable during movement of recently irradiated fuel assemblies in the fuel handling building, suspend movement of recently irradiated fuel assemblies in the fuel handling building. This does not preclude the movement of fuel assemblies to a safe position.

SURVEILLANCE REQUIREMENTS

Once actuated due to a fuel handling accident the FHBVS must be protected against a single failure coincident with a loss of offsite power. Protection against a loss of power, although not required for immediate accident response, is assured by requiring that a backup power supply be provided as described above in the LCO section. This back up is assured via the performance of non-TS surveillances.

SR 3.7.13.1

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check on this system. This testing requires establishing air flow through both the HEPA filters and charcoal adsorbers.

Systems without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.13.2

This SR verifies that the required FHBVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The FHBVS filter tests are in accordance with References 5 and 6. The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.13.3

This SR verifies that each FHBVS train starts and operates on an actual or simulated actuation signal and directs its exhaust flow through the HEPA Filters and charcoal adsorber banks. 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 (continued)

SR 3.7.13.4

This SR verifies the integrity of the fuel handling building enclosure. The ability of the fuel handling building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the FHBVS. During the post accident mode of operation, the FHBVS is designed to maintain a slight negative pressure in the fuel handling building, to prevent unfiltered LEAKAGE. The FHBVS is designed to maintain the building pressure ≤ -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.

SR 3.7.13.5

Operation of damper M-29 is necessary to ensure that the system functions properly. The operability of damper M-29 is verified if it can be closed. 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 9.4.4.
2. UFSAR, Section 15.5.
3. Regulatory Guide 1.183, July 2000.
4. 10 CFR 50.67.
5. ASTM D 3802-1989
6. ANSI N510-1980.
7. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.
8. DCM S-23D, "Fuel handling Building HVAC System."
9. Regulatory Guide 1.183, July 2000.
10. License Amendment 184/186, January 3, 2006.
11. PG&E Letter DCL-05-124
12. License Amendment 163/165, February 27, 2004.

B 3.7 PLANT SYSTEMS

B 3.7.14 Not Used

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Storage Pool Water Level

BASES

BACKGROUND	The minimum water level in the spent fuel 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 spent fuel 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, Sections 15.4.5 and 15.5.22 (Ref. 3).
APPLICABLE SAFETY ANALYSES	The minimum water level in the spent fuel 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 a small fraction of the 10 CFR 50.67 (Ref. 5) limits. According to Reference 4, there is 23 ft of water between the top of the damaged fuel rods and the fuel pool surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 4 can be used directly. Although there are other spent fuel pool elevations where fuel handling accidents can occur, the design basis fuel handling accident, which uses the conservative assumptions of RG 1.183, is expected to be bounding. To add conservatism, the analysis assumes that all fuel rods of the damaged fuel assembly fail. In practice, the water level maintained for fuel handling provides more than 23 feet of water over the top of irradiated fuel assemblies seated in the storage racks. UFSAR Section 9.1.4.3.6 requires the water level provide a minimum of 8 feet of water shielding during fuel handling. This assures more than 24 feet 6 inches of water shielding over the top of the fuel assemblies in the racks and more than 23 feet of water shielding over a fuel assembly lying horizontally on top of the racks. The spent fuel pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The spent fuel 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.

(continued)

BASES (continued)

APPLICABILITY	This LCO applies during movement of irradiated fuel assemblies in the spent fuel pool, since the potential for a release of fission products exists.
ACTIONS	<u>A.1</u> 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 spent fuel pool water level is lower than the required level, the movement of irradiated fuel assembly in the spent fuel pool is immediately suspended. 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	<u>SR 3.7.15.1</u> This SR is done during the movement of irradiated fuel assemblies as stated in the Applicability. This SR verifies sufficient fuel storage pool water is available in the event of a fuel handling accident. The water level in the spent fuel 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. During refueling operations, the level in the spent fuel 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, Sections 9.1.4.3.6, 15.4.5 and 15.5.22. 4. Regulatory Guide 1.183, July 2000. 5. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.16 Spent Fuel Pool Boron Concentration

BASES

BACKGROUND

The DCPP Units 1 and 2 spent fuel pools (Ref. 4) each consist of 16 permanent stainless steel racks of various sizes, with a total of 1,324 fuel assembly storage cells. For cycles 14 – 16, in addition to the 16 racks, a cask pit storage rack with a capacity of 154 cells is installed in each spent fuel pool's cask pit area. This extra rack expands the total storage capacity in each spent fuel pool to 1,478 fuel assembly storage cells. The spent fuel pool storage racks have been analyzed for the storage of fuel assemblies that meet the requirements of LCO 3.7.17. The fuel storage capacity during cycles 14 – 16 is 1478 assemblies, of which 1433 assemblies may be irradiated. Unfilled cells in the permanent storage racks may be utilized for the storage of unirradiated fuel assemblies. The limitation of a maximum of 1433 irradiated assemblies is based on the spent fuel pool bulk temperature analysis for cycles 14 – 16, while the cask pit storage rack is installed.

10 CFR 50.68(b)(4), requires that the spent fuel storage racks are designed to assure that with credit for soluble boron and with fuel of the maximum fuel assembly reactivity, a K_{eff} of less than or equal to 0.95 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with borated water, and a K_{eff} of less than 1.0 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with unborated water.

Criticality analyses have been performed for the permanent storage racks (Ref. 3 and 5) and for the cask pit storage rack (Ref 8), which demonstrate that the multiplication factor, k_{eff}, of the fuel assemblies in the spent fuel storage racks is less than or equal to 0.95. In order to maintain k_{eff} less than or equal to 0.95, the presence of soluble boron is credited in the spent fuel pool criticality analyses.

For the permanent storage racks, Reference 5 provides the analysis for the 2x2 array and checkerboard configurations, and Reference 3 provides the analysis for the all cell configuration. Both criticality analyses (Ref. 3 and 5) evaluate the region of the spent fuel pool that does not contain any Boraflex panels because the storage requirements are more restrictive and yield more conservative reactivity results than the region containing Boraflex. The results of the analyses may be conservatively applied to the less reactive region.

(continued)

BASES

BACKGROUND (continued)

Reference 8 provides the analysis for the cask pit storage rack. Storage configurations were defined in the criticality analysis (Ref. 8) to ensure that k_{eff} will be less than 1.0 with no soluble boron under normal storage conditions including tolerances and uncertainties. Soluble boron credit is then used to maintain k_{eff} less than or equal to 0.95. A minimum soluble boron concentration of 500 ppm is required to maintain k_{eff} less than or equal to 0.95 under normal storage conditions including tolerances and uncertainties, which is well within the 2000 ppm requirement of LCO 3.7.16.

The criticality analyses considered accident conditions (Ref. 3, 5, and 8). Soluble boron credit is then used to maintain k_{eff} less than or equal to 0.95 and to mitigate the worst accident reactivity insertion. For the permanent storage racks, a soluble boron concentration of 806 ppm is required to maintain k_{eff} less than or equal to 0.95 for all allowable storage configurations, which is well within the 2000 ppm requirement of LCO 3.7.16. For the cask pit storage rack, a soluble boron concentration of 800 ppm is required to maintain keff less than or equal to 0.95 for all allowable storage configurations, which is well within the 2000 ppm requirement of LCO 3.7.16.

For such an occurrence, the double contingency principle of ANSI N16.1-1975 and the April 1978 NRC letter (Ref. 1) can be applied. The NRC letter states it is not required to assume two unlikely, independent, concurrent events to ensure protection against a criticality accident. Thus, for such a postulated reactivity insertion accident condition, the presence of soluble boron in the spent fuel pool water can be assumed as a realistic initial condition since not assuming its presence would be a second unlikely event.

In addition to consideration of spent fuel pool criticality, a boron dilution analysis (Ref. 6) was performed to evaluate the time and water volumes required to dilute the spent fuel pool from 2000 to 800 ppm.

The results of the boron dilution analysis concluded that an unplanned or inadvertent event that would result in the dilution of the spent fuel pool boron concentration from 2000 ppm to 800 ppm is not a credible event since a dilution event large enough to result in a significant reduction in the spent fuel pool boron concentration would involve the transfer of a large quantity of water from a dilution source and a significant increase in spent fuel pool level, which would ultimately overflow the pool. The overflow of the spent fuel pool would be readily detected and terminated by plant personnel. In addition, because of the large quantities of water required and the low dilution flow rates available, any significant dilution of the spent fuel pool boron concentration would only occur over a long period of time (hours to days).

(continued)

BASES

BACKGROUND (continued)	Detection of a spent fuel pool boron dilution via pool level alarms, visual inspection during normal operator rounds, significant changes in spent fuel pool boron concentration, or significant changes in the unborated water source volume, would be expected before a dilution event sufficient to increase K_{eff} above 0.95 could occur. However, for the permanent storage racks analyses have been performed to demonstrate that even if the spent fuel pool boron concentration was diluted to zero ppm, which would take significantly more water than evaluated in the boron dilution analysis, the spent fuel would be expected to remain subcritical and the health and safety of the public would be assured.
APPLICABLE SAFETY ANALYSES	Most accident conditions result in a negligible reactivity effect in the spent fuel pool (Ref. 3, 5, and 8). However, scenarios can be postulated that could have more than a negligible positive reactivity effect. Examples of such accident scenarios for the permanent storage racks are the misplacement of a fuel assembly, a significant increase in spent fuel pool temperature above 150°F, or a cask drop accident (Ref. 4). A soluble boron concentration of 806 ppm is required to maintain k_{eff} less than or equal to 0.95 under accident conditions, which is well within the 2000 ppm requirement of LCO 3.7.16. Examples of accident scenarios for the cask pit storage rack are the misplacement of a fuel assembly and a dropped assembly. A soluble boron concentration of 800 ppm is required to maintain k_{eff} less than or equal to 0.95 under accident conditions, which is well within the 2000 ppm requirement of LCO 3.7.16. The negative reactivity effect of the soluble boron more than compensates for the increased reactivity caused by the postulated accident scenarios. The accident analyses is provided in the UFSAR (Ref. 4). The concentration of dissolved boron in the spent fuel pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The spent fuel pool boron concentration is required to be ≥ 2000 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential criticality accident scenarios as described in References 3, 4, 5, and 8. The specified boron concentration of 2000 ppm ensures that the spent fuel pool k_{eff} will remain less than or equal to 0.95 at a 95 percent probability, 95 percent confidence level, for a postulated reactivity insertion accident or boron dilution event.
APPLICABILITY	This LCO applies whenever fuel assemblies are stored in the spent fuel pool.

(continued)

BASES (continued)

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 spent fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies and immediately taking actions to restore the spent fuel pool boron concentration to greater than or equal to 2000 ppm. This suspension of fuel movement does not preclude movement of fuel assemblies to a safe position.

If the LCO is not met while moving fuel assemblies LCO 3.0.3 would not be applicable since the inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies by chemical analysis that the concentration of boron in the spent fuel pool is at or above 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. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).
2. Not used.
3. "Criticality Safety Evaluation of Region 2 of the Diablo Canyon Spent Fuel Storage Racks with 5.0 % Enrichment," S.E.Turner, October 1993, Holtec Report HI-931077.
4. UFSAR, Sections 9.1, 15.4.5, and 15.5.22.
5. "Diablo Canyon Units 1 and 2 Spent Fuel Criticality Analysis," February 14, 2001, Paul F. O'Donnell, Westinghouse Doc. No. A-DP1-FE-0001.
6. "Diablo Canyon Units 1 and 2 Spent Fuel Pool Boron Dilution Source Analysis," M-1188 (SAP Calculation No, 9000041656), December 2016
7. License Amendment 154/154, September 25, 2002.
8. “Spent Fuel Storage Expansion at Diablo Canyon Units 1 & 2 for Pacific Gas & Electric Co.”, October 2004, Holtec Report HI-2043162.
9. License Amendment 183/185, November 21, 2005.

B 3.7 PLANT SYSTEMS

B 3.7.17 Spent Fuel Assembly Storage

BASES

BACKGROUND

The DCPP Units 1 and 2 spent fuel pools (Ref. 2) each consist of 16 stainless steel racks of various sizes, with a total of 1,324 fuel assembly storage cells. For cycles 14 – 16, in addition to the 16 permanent racks, a cask pit storage rack with a capacity of 154 cells is installed in each spent fuel pool's cask pit area. This extra rack expands the total storage capacity in each spent fuel pool to 1,478 fuel assembly storage cells. The spent fuel pool storage racks have been analyzed for the storage of fuel assemblies which meet the requirements of LCO 3.7.17. The fuel storage capacity during cycles 14 – 16 is 1478 assemblies, of which 1433 assemblies may be irradiated. Unfilled cells in the permanent storage racks may be utilized for the storage of unirradiated fuel assemblies. The limitation of a maximum of 1433 irradiated assemblies is based on the spent fuel pool bulk temperature analysis for cycles 14 – 16, while the cask pit storage rack is installed. The 16 permanent spent fuel storage racks are designed to accommodate three different storage configurations as shown in Figure 3.7.17-1. The cask pit fuel storage rack is designed to accommodate only fuel with an initial enrichment of ≤ 4.1 weight % U-235, a minimum 10 year decay time and a discharge burnup in the acceptable region of Figure 3.7.17-4.

10 CFR 50.68(b)(4), requires that the spent fuel storage racks are designed to assure that with credit for soluble boron and with fuel of the maximum fuel assembly reactivity, a K_{eff} of less than or equal to 0.95 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with borated water, and a K_{eff} of less than 1.0 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with unborated water.

Criticality analyses have been performed (Ref. 3, 4, and 6) which demonstrate that the multiplication factor, k_{eff}, of the fuel assemblies in the spent fuel storage racks is less than or equal to 0.95. In order to maintain k_{eff} less than or equal to 0.95, the presence of soluble boron is credited in the spent fuel pool criticality analysis. Reference 3 provides the analysis for the 2x2 array and checkerboard configurations, Reference 4 provides the analysis for the all cell configuration, and Reference 6 provides the analysis for the cask pit storage rack.

(continued)

BASES

BACKGROUND (continued)	For the 16 permanent storage racks, both criticality analyses (Ref. 3 and 4) evaluate the region of the spent fuel pool that does not contain any Boraflex panels because the storage requirements are more restrictive and yield more conservative reactivity results than the region containing Boraflex. The results of the analyses may be conservatively applied to the less reactive region. A discussion of how soluble boron is credited for the storage of fuel assemblies in the spent fuel pool is contained in the background for TS 3.7.16 Bases. Storage configurations were defined in the criticality analyses (Ref. 3, 4, and 6) to ensure that k_{eff} will be less than 1.0 with no soluble boron under normal storage conditions including tolerances and uncertainties. Soluble boron credit is then used to maintain k_{eff} less than or equal to 0.95 and to mitigate the worst accident reactivity insertion. For the permanent storage racks, a soluble boron concentration of 806 ppm is required to maintain k_{eff} less than or equal to 0.95 for all allowable storage configurations, which is well within the 2000 ppm requirement of LCO 3.7.16. For the cask pit storage rack, a soluble boron concentration of 800 ppm is required to maintain k_{eff} less than or equal to 0.95 for all allowable storage configurations, which is well within the 2000 ppm requirement of LCO 3.7.16. Prior to movement of an assembly, it is necessary to verify that SR 3.7.16.1 is current.
APPLICABLE SAFETY ANALYSES	For the permanent storage racks, the analyzed accidents that could have significant reactivity effects are the misplacement of a fuel assembly, a significant increase in spent fuel pool temperature above 150°F, or a cask drop accident (Ref. 2, 3, and 4). For the cask pit storage rack, accidents that could have significant reactivity effects are misplacement of a fuel assembly and a dropped assembly (Ref. 6). For these accident occurrences, the presence of soluble boron in the spent fuel storage pool (controlled by LCO 3.7.16, "Spent Fuel Pool Boron Concentration") ensures that k_{eff} will remain at or below 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 LCO 3.7.17, ensure the k_{eff} of the spent fuel storage pool will always remain ≤ 0.95 at a 95 percent probability, 95 percent confidence level, for a postulated reactivity insertion accident or a boron dilution event.
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in the spent fuel pool.

(continued)

BASES (continued)

ACTIONS	<u>A.1</u> The Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply since the inability to move fuel assemblies is not sufficient reason to require a reactor shutdown. When the configuration of fuel assemblies stored in the spent fuel pool is not in accordance with LCO 3.7.17, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with LCO 3.7.17 which will return the fuel pool to an analyzed condition.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.17.1</u> This SR verifies by administrative means that each fuel assembly and its expected storage location are in accordance with LCO 3.7.17 prior to each fuel assembly move when the assembly is to be stored in the spent fuel pool. A complete record of initial enrichment, initial integral boron content, fuel pellet diameter, and the cumulative burnup analysis shall be maintained for the time period that each fuel assembly remains in the spent fuel pool. In addition, for fuel assemblies stored in the cask pit storage rack, the record will also include fuel assembly decay-time.
REFERENCES	1. Not used. 2. UFSAR, Sections 9.1, 15.4.5, and 15.5.22. 3. "Diablo Canyon Units 1 and 2 Spent Fuel Pool Criticality Analysis," February 14, 2001, Paul F. O'Donnell, Westinghouse Doc. No. A-DP1-FE-0001. 4. "Criticality Safety Evaluation of Region 2 of the Diablo Canyon Spent Fuel Storage Racks with 5.0 % Enrichment," S.E.Turner, October 1993, Holtec Report HI-931077. 5. License Amendment 154/154, September 25, 2002. 6. "Diablo Canyon Units 1 and 2 Spent Fuel Storage Expansion Licensing Report", October 2004, Holtec Report HI – 2043162. 7. License Amendment 183/185, November 21, 2005.

B 3.7 PLANT SYSTEMS

B 3.7.18 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 0.75 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). Operating at or below 0.1 μCi/gm ensures that in the event of a DBA, offsite doses will be less than 10 CFR 50.67 requirements.
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 10 CFR 50.67 limits (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 atmospheric dump valves (ADVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 generators are assumed to discharge steam and any entrained activity through the MSSVs and ADVs during the event. The quantity of radioactivity released to the environment, due to an SGTR, depends upon primary and secondary coolant activity, iodine spiking effects, primary to secondary break flow flashing fractions, attenuation of iodine carried by the flashed portion of the break flow, partitioning of iodine between the liquid and steam phases, the mass of fluid released from the steam generator, and liquid-vapor partitioning in the condenser hotwell. All of these parameters were conservatively evaluated in a manner consistent with the recommendations of Standard Review Plan Section 15.6.3 and 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 a small fraction of 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.
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	<u>A.1 and A.2</u> 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

(continued)

BASES

ACTIONS	A.1 and A.2 (continued) 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 3.7.18.1 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. 10 CFR 50.67. 2. UFSAR, Chapter 15

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 power sources (normal and alternate), and the onsite standby power sources (three diesel generators (DGs) for each unit). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System for each unit is divided into three load groups so that the loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two offsite power sources and a single DG.

Offsite power is supplied to the 230-kV and 500-kV switchyards from the transmission network by two 230-kV transmission lines and three 500-kV transmission lines. These two electrically and physically separated circuits provide AC power, through auxiliary and standby startup transformers, to the 4.16-kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E 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 buses.

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within 1 minute after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe, condition are returned to service via the load sequencer timers (auto transfer timers). Each individual timer connects a single ESF component.

The onsite standby power source for each 4.16-kV ESF bus is a dedicated DG. For Unit 1, DGs 1-1, 1-2, and 1-3 are dedicated to ESF buses H, G, and F, respectively. For Unit 2, DGs 2-1, 2-2, and 2-3 are dedicated to ESF buses G, H, and F. A DG starts automatically on a safety injection (SI) signal (e.g., low pressurizer pressure or high containment pressure signals), undervoltage on the offsite standby startup source, or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator

(continued)

BASES

BACKGROUND (continued)

(DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to their respective ESF bus by the load sequencing timers (ESF timers). The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG. Each ESF component is provided with its own load sequencing timer.

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

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for the six DGs satisfy the requirements of Safety Guide 9, March 1971 (Ref.3).

The net electrical output ratings of the DGs are as follows:

a. 2600 kW at 0.8 Power Factor (PF) for continuous operation; and

b. 2750 kW for overload operation (2000 hours in a 1 year period); and

c. 2860 kW for overload operation (2 hours in a 24 hour period); and

d. 3056 kW for overload operation (30 minute rating)

The ESF loads that are powered from the 4.16-kV ESF buses are listed, in part, in UFSAR Chapter 8 (Ref. 2).

(continued)

BASES

BACKGROUND (continued)	Fuel oil is transferred from the storage tanks via the diesel fuel oil storage and transfer system to replenish the day tanks as required. The design incorporates sufficient redundancy so that a malfunction of either an active or a passive component will not impair the ability of the system to supply fuel oil. Two redundant fuel oil transfer pumps supply fuel oil to each DG day tank from either storage tank. One pump is adequate to supply the six DGs operating at full load. Each DG tank has two separate, redundant transfer pump start-stop level switches. Each level switch automatically starts a transfer pump and opens the supply header solenoid valve corresponding to the respective transfer pump, 0-1 or 0-2. The day tank level switches are considered part of the associated DG rather than the diesel fuel oil transfer system, since level switch failure impacts the capability of one of the diesel fuel oil transfer system trains to transfer fuel to the associated DG only. In March 2014, License Amendment Request 14-01, "Revision to Technical Specification 3.8.1 'AC Sources – Operating'" was submitted to NRC, to modify several EDG surveillance requirements (Ref. 24). In July 2015, LAR 14-01 was reviewed and approved by NRC (LA 218/220) (Ref. 25). Refer to LAR 14-01 or LA 218/220 for details associated with various surveillance requirements.
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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 ESF systems powered by 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 sources; and b. A worst case single failure in either the onsite AC electrical power sources or the Class 1E Electrical Power Distribution System. The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System and separate and independent DGs for each Class 1E ESF bus ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses. The Unit 1 Offsite Circuit #1 consists of Startup Transformer 1-1 supplied from the immediate access 230-kV Switchyard power source [Unit 1 and Unit 2 share these components of the 230-kV system: 230-kV switchyard breaker 212, 230-kV station tie line, 230-kV disconnect switches 211, 213, and 215], which feeds Startup Transformer 1-2 through series supply breakers 52VU12 and 52VU14. Startup Transformer 1-2 then supplies power through breaker 52HG15 to each Class 1E bus feeder breaker (Bus F - 52HF14, Bus G - 52HG14, Bus H - 52HH14). The Unit 1 Offsite Circuit #2 is the delayed access 500-kV circuit which becomes available only after opening the motor operated disconnect to the main generator. This circuit consists of Auxiliary Transformer 1-2 supplied from the 500-kV Switchyard through the main bank transformers. Auxiliary Transformer 1-2 supplies power directly to each of the Class 1E bus feeder breakers (Bus F - 52HF13, Bus G - 52HG13, Bus H - 52HH13).

(continued)

BASES

LCO (continued)

The Unit 2 Offsite Circuit #1 consists of Startup Transformer 2-1 supplied from the immediate access 230-kV Switchyard power source [Unit 1 and Unit 2 share these components of the 230-kV system: 230-kV switchyard breaker 212, 230-kV station tie line, 230-kV disconnect switches 211, 213, and 215], which feeds Startup Transformer 2-2 through series supply breakers 52VU23 and 52VU24. Startup Transformer 2-2 then supplies power through breaker 52HG15 to each Class 1E bus feeder breaker (Bus F - 52HF14, Bus G - 52HG14, Bus H - 52HH14). The Unit 2 Offsite Circuit #2 is a delayed access circuit which only becomes available after opening the motor operated disconnect to the main generator. This circuit consists of Auxiliary Transformer 2-2 supplied from the 500-kV Switchyard through the main bank transformers. Auxiliary Transformer 2-2 supplies power directly to each of the Class 1E bus feeder breakers (Bus F - 52HF13, Bus G - 52HG13, Bus H - 52HH13).

Operating Procedure OP J-2:VIII (Ref. 20) provides guidelines for determining the operability of the 230-kV and 500-kV offsite power sources based on existing grid and plant conditions.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine pre-lubed and pre-warmed. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to automatically sequence the emergency loads onto the DG, following opening of the auxiliary breaker, on an ESF actuation signal while operating in parallel test mode.

The AC sources must be separate and independent (to the extent possible). For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. The delayed access circuit (500-kV Auxiliary) is normally connected to all three ESF Buses during power operation. If this circuit is not connected to an ESF Bus, it is provided with a manual transfer mechanism (Delayed Access) to support circuit OPERABILITY. The immediate access circuit (230-kV Startup) is not normally connected to an ESF Bus but is provided with an OPERABLE automatic transfer interlock mechanism initiated by bus undervoltage to support circuit OPERABILITY.

The two redundant diesel fuel oil supply trains supply fuel oil to DG day tanks from either storage tank. One pump supply train is adequate to supply the six DGs operating at full load.

(continued)

BASES (continued)

APPLICABILITY

The AC sources 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 PG&E Design Class I functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

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

A.1

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

A.2

Operation may continue in Condition A for a period that should not exceed 72 hours (Ref. 6). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

(continued)

BASES

ACTIONS

A.2 (continued)

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.

B.1

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

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are powered from the three AC electrical power distribution subsystems (buses). Required features are redundant PG&E Design Class I systems, subsystems, trains, components, and devices that depend on the diesel generators as a source of emergency power. Redundant required feature failures consist of inoperable features associated with one of the other Class 1E AC electrical power distribution subsystems, redundant to the subsystem associated with the inoperable DG.

(continued)

BASES

ACTIONS

B.2 (continued)

An example, if DG 1-1 (Bus H) were declared inoperable with safety injection pump 1-1 (Bus F) already inoperable. SIP 1-2 (Bus H) would then be required to be declared inoperable within 4 hours, and TS 3.0.3 entered. A Note has been added to point out that during operation in MODES 1, 2, and 3, two auxiliary feedwater pumps are required to meet the redundant features requirement to mitigate a feedwater line break. If both of the available AFW pumps are motor driven, neither of the two may be supplied by the DG which is inoperable. For example, declaring DG 1-1 (Bus H) inoperable would require maintaining the turbine driven AFW pump and motor driven AFW pump 1-3 OPERABLE, while declaring DG 1-2 (Bus G) inoperable would not impact redundant required features since no AFW pumps are associated with Bus G.

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 DG exists; and

b. A required feature, redundant to a required feature associated with the inoperable DG on one of the other Class 1E AC electrical power distribution subsystems, is inoperable.

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

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

In this Condition, the remaining two OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the 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.

(continued)

BASES

ACTIONS (continued)

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DGs, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DGs, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DGs. If a DG has already started and loaded on a bus, it is not necessary to shutdown the DG and perform SR 3.8.1.2. The DG is verified OPERABLE since it is performing its intended function.

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

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

Operation may continue in Condition B for a period that should not exceed 14 days. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

In Condition B, the remaining OPERABLE DGs and offsite circuits 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.

(continued)

BASES

ACTIONS

B.4 (continued)

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

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The rationale for the reduction to 12 hours for Required Action C.1 is provided in Reference 6, which supports a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. When a concurrent redundant required feature failure exists, this assumption is not valid, and a shorter Completion Time of 12 hours is appropriate. Required features are redundant PG&E Design Class I systems, subsystems, trains, components, and devices that depend on the DGs as a source of emergency power. These features are powered from the three Class 1E AC electrical power distribution subsystems. Examples of required features would include, but are not limited to, auxiliary saltwater pumps, centrifugal charging pumps, or motor-driven auxiliary feedwater pumps.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Operation may continue in Condition C for a period that should not exceed 24 hours (Ref. 6). This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the Class 1E AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a DBA, 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.

D.1 and D.2

Operation may continue in Condition D for a period that should not exceed 12 hours (Ref. 6). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

In Condition D, individual redundancy is lost in the offsite electrical power system and may be lost in 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

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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

E.1

With two or more DGs inoperable, the remaining onsite AC sources are inadequate. 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 may be 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, 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 two or more DGS inoperable, operation may continue for a period that should not exceed 2 hours.

F.1

Condition F corresponds to a level of degradation in which one train of the DFO transfer system is inoperable. The onsite AC electrical power systems are redundant and available to support ESF loads. However, one subsystem required for the onsite AC electrical system operability has lost its redundancy (DFO supply to the DGs).

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. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

(continued)

BASES

ACTIONS

G.1

With both trains of DFO inoperable, the onsite AC sources are inadequate (loss of DFO supply to all DGs). With an assumed loss of offsite electrical power, insufficient AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source for 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, 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.

(continued)

BASES

ACTIONS (continued)

H.1 and H.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 overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 26). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 26, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action H.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

(continued)

BASES

ACTIONS (continued)	I.1 Condition I corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, further loss of the remaining offsite circuit 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. J.1 Condition J corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, further loss of a remaining DG will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.
SURVEILLANCE REQUIREMENTS	The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of NUREG-1431, Revision 1 (Ref. 15) and Regulatory Guide 1.108, Revision 1 (Ref. 9) for the types of surveillance tests and surveillance frequencies, and Regulatory Guide 1.137, Revision 1 (Ref. 10), as addressed in the UFSAR.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3980 V is greater than the second level undervoltage relay allowable values. 3980 V is 95.7 percent of the nominal 4160 V output voltage. This value, which is 240 V above the minimum utilization voltage specified in ANSI C84.1 (Ref. 21) allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90 percent or 3600 V. The minimum steady state voltage on the 4.16-kV Class 1E buses ensures adequate 4160 V, 480 V, and 120 Vac levels. The specified maximum steady state output voltage of 4340 V is less than the maximum operating voltage for 4000 V motors specified in ANSI C84.1 (4400 V). The maximum steady state output voltage of 4340 V 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 steady-state voltages and frequencies for this Surveillance are 3980 V and 4340 V and 59.2 Hz and 60.8 Hz, respectively, which are equivalent to 4160 V ± 4.33% and 60 Hz ± 1.33%. The maximum loading conditions associated with the voltage and frequency limits must be bounded by this Surveillance in order to verify that the steady-state loading of the Class 1E 4.16-kV ESF buses under maximum voltage (4340 V) and frequency (60.8 Hz) conditions following a postulated DBA does not exceed the Safety Guide 9 (Ref. 3) Regulatory Position C.2 limit for predicted loads, which includes derating the diesel generators due to temperature effects.

In accordance with the guidance provided in Safety Guide 9, March 1971 (Ref. 3), Regulatory Position C.4, where steady state conditions do not exist (i.e., transients), the frequency range should be restored to within ± 2% of the 60 Hz nominal frequency (58.8 Hz to 61.2 Hz) and the voltage range should be restored to within ±10% of the 4160 V nominal voltage (3740 V to 4580 V). The timed start is satisfied when the DG achieves at least 3785 V and 58.8 Hz. At these values, the DG output breaker permissives are satisfied, and on detection of bus undervoltage or loss of power, the DG breakers would close, reenergizing its respective ESF bus.

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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 their preferred power source, 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. SRs 3.8.1.2 and 3.8.1.7 satisfy Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.c (1) by demonstrating proper DG startup and verifying that the required voltage and frequency are automatically attained within acceptable limits and time. This test should also verify that the components of the diesel generator unit required for automatic startup are operable.

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 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and, for SR 3.8.1.2, 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 DGs are started from standby conditions. Standby conditions for a DG means that the diesel engine coolant and oil temperature is being maintained consistent with manufacturer recommendations of equal to or greater than 90°F but less than 175°F. For the purposes of this SR, the diesel generator start will be initiated using one of the following signals: 1) manual, 2) simulated loss of offsite power, and 3) safety injection actuation test signal.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

SR 3.8.1.7 requires that the DG starts from standby conditions and achieves minimum required voltage and frequency within 10 seconds. The 10 second start requirement reflects the point during the DG's acceleration at which the DG is assumed to be able to accept load. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

Since SR 3.8.1.7 requires a timed start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

SR 3.8.1.2 and SR 3.8.1.7 require the DG achieves steady state voltage and frequency within limits. Actual steady state operation is expected to achieve a level of stability closer to the nominal 60 Hz value. In addition to the SR requirements, the time for the DG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The Surveillance Frequency is 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 DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source. SR 3.8.1.3 satisfies Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.c.(2), by demonstrating that the DG is capable of carrying the expected maximum load following a design basis accident for an interval of not less than one hour and that the DG cooling system functions within design limits. The manufacturer recommendation for jacket water outlet temperature is less than 185°F and lube oil temperature is less than 195°F.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The test load criterion is provided to avoid exceeding vendor ratings. The test load criterion is 2860 kW (nominal), less instrument uncertainty, a test band and diesel generator derating. This criterion will load the DG at a load greater than the calculated worst-case maximum steady state load as determined by the latest DG steady state loading analyses, up to the 2-hours in a 24 hour period rating. OPERATION as near to the 2-hour rating as practical without exceeding the DG rating will provide adequate assurance of the machine's ability to carry 100% of rated full load if 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 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 satisfies Regulatory Guide 1.108 (Ref. 9), Regulatory Positions C.1.b.(1) and C.2.b, in part, by requiring the redundant DG units to be tested independently (nonconcurrently). Note 3 indicates that this Surveillance should be conducted on only one DG at a time per unit in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is a contained quantity sufficient for DG operation at full load for a nominal one-hour period. One hour is adequate time for an operator to take corrective action to restore the fuel oil supply to the affected day tank. Each DG shall be equipped with a day tank whose capacity is sufficient to maintain at least 60 minutes of operation. The volume of fuel required is equal to the usable minimum volume of 258 gallons plus the un-usable volume (which is slightly different for each day tank) and the amount of fuel remaining in the DFO Priming Tanks at the low level alarm setpoint. This volume supports one hour of DG operation which is sufficient to supply the DG loading at 2750 kW of the Class 1E 4.16-kV ESF buses under worst-case conditions of voltage (4340 V) and frequency (60.8 Hz) following a postulated DBA, plus additional fuel volume margin. The day tank low level alarm setpoint, including instrument uncertainty, is such that annunciation is provided prior to reaching this fuel oil level in the day tank.

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 DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from the fuel oil storage tanks to each day tank. SR 3.8.1.6 satisfies Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(7), by demonstrating that the engine will perform properly if switching from one fuel oil supply system to another. This is a part of the normal operating procedure to satisfy the 7-day storage requirement. 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 automatic fuel transfer systems are OPERABLE.

The two redundant diesel fuel oil supply trains are common to both units. The automatic controls (e.g., day tank level switches) are normally configured such that one unit is set to preferentially draw diesel fuel from one storage tank while the other unit draws preferentially from the other storage tank. Each unit's automatic controls are set to use the other unit's preferred storage tank as its backup (Ref. 22). Either of the fuel oil transfer trains may get actuated during this surveillance testing; however, auto start and valve line up shall be demonstrated for both fuel oil transfer trains, for operability of the fuel oil transfer system (Ref. 23).

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

Special Configuration - DFO Storage Tank Cleaning Activity: The TS 3.8.3 LCO Note permits DFO storage tank cleaning to be performed and the DFO storage tank being cleaned may be inoperable for up to 10 days (Ref. 27). During DFO storage tank cleaning, the transfer pump in the train with DFO storage tank removed from service is aligned and available for operation with the pump control switch in the “OFF” position. This temporary alignment prevents inadvertent simultaneous operation of both transfer pumps using the same suction line. In the event the transfer pump associated with the in service DFO storage tanks fails upon demand, the transfer pump in the train with DFO storage tank removed from service will be started by operator action in response to alarms indicating a trip of the operating fuel oil transfer system. The fuel oil transfer pump associated with the tank to be cleaned remains operable in this special configuration and is available for manual start. The TS-specified DG day tank minimum volume will continue to fuel the DGs while the manual action is taken to start the transfer pump (Ref 28).

SR 3.8.1.7

Refer to SR 3.8.1.2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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, which is the immediate access 230-kV, demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. Transfer of each 4.16kV ESF bus power supply from the alternate offsite circuit (immediate access 230-kV) to the delayed access circuit (500-kV circuit) demonstrates the ability of the delayed access circuit. 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, during operation with the reactor critical, performance of this SR for automatic bus transfers could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. The restriction applies only to automatic bus transfers where a unit trip and reactor trip will occur.

This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operating procedures that are available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. This restriction does not apply to manual bus transfers which are a normal action required during a plant startup or shutdown.

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in MODES 3, 4, 5, or 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. SR 3.8.1.9 satisfies Safety Guide 9, March 1971, RP C.4 (Ref. 3), in part, and RG 1.108, Revision 1, RP C.2.a.(4) (Ref. 9), in part, by demonstrating proper operation during DG load rejection, including a test of the loss of the largest single load. The single largest DG load is a centrifugal charging pump (CCP), which is powered by a motor rated at 600 hp. The CCP has a maximum electrical demand based on the maximum expected horsepower input, maximum operational frequency and motor efficiency of approximately 542 kW. For conservatism, a load reject equal to or greater than 600 kW is used to bound this demand under worst case conditions. This Surveillance may be accomplished by:

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

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

c. Simultaneously tripping a combination of loads equal to or greater than the DG's associated single largest post-accident load with the DG solely supplying the bus.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

The 1.6 seconds specified is equal to 40% of a typical 4 second load sequence interval associated with sequencing of the largest load. The specified minimum and maximum voltage and frequencies for SR 3.8.1.9 are 3785 V and 4400 V and 58.8 Hz and 61.2 Hz, respectively, which corresponds to 4160 V + 5.77%, - 9% and 60 Hz ± 2%. These values satisfy the voltage and frequency recovery recommendations given in Safety Guide 9, March 1971 (Ref. 3), Regulatory Position C.4. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are transient 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 two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operating procedures that are available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in MODES 3, 4, 5, or 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed using a power factor ≤ 0.9 lagging. This power factor is chosen to be representative of the single largest load used during the performance of this Surveillance.

SR 3.8.1.10

This Surveillance demonstrates the DG's capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. This Surveillance satisfies Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(4), in part, by demonstrating proper operation during DG load shedding, including a test of complete loss of load, and verifying that the voltage requirements are met and that the overspeed limits are not exceeded. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG would experience following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

This SR is modified by a Note. The reason for the Note is to ensure that the DGs are tested under load conditions that are as close to design basis conditions as practicable.

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 (continued)

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), Regulatory Position C.2.a.(1), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite power 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 DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis accident. The 10 second requirement reflects the assumption of the accident analysis that the DG has reached the point in its acceleration where the DG is able to accept load. 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. After energization of the loads, steady state voltage and frequency are required to be within their limits.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. The permanently connected loads are the Class 1E 480-V buses. The permanently connected loads do not receive a load shed signal. In addition, the containment fan cooler units do not receive a load shed signal but are de-energized when their motor contactors drop out on undervoltage. The permanently connected loads are re-energized when the DG breaker closes to energize the bus. The auto-connected loads are those loads that are energized via their respective sequencing timer. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The specified minimum and maximum steady state voltages and frequencies for this Surveillance are 3980 V and 4340 V and 59.2 Hz and 60.8 Hz, respectively, which are equivalent to 4160 V ± 4.33% and 60 Hz ± 1.33%. The maximum loading conditions associated with the voltage and frequency limits must be bounded by this Surveillance, in order to verify that the steady-state loading of the Class 1E 4.16-kV ESF buses under maximum voltage (4340 V) and frequency (60.8 Hz) conditions following a postulated DBA does not exceed the Safety Guide 9 (Ref. 3) Regulatory Position C.2 limit for predicted loads, which includes derating the diesel generators due to temperature effects.

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 DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations of equal to or greater than 90°F but less than 175°F. 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 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 plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operating procedures that are available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in MODES 5 or 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

As required by Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(2), this Surveillance demonstrates proper operation for design accident loading-sequence to design-load requirements and verify that voltage and frequency are maintained within required limits.

This Surveillance demonstrates that the DG automatically starts and achieves stability by reaching the minimum required voltage and frequency within the specified time (10 seconds) from the Safety Injection actuation signal, and subsequently achieves steady state voltage and frequency, and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

The specified minimum and maximum steady state voltages and frequencies for this Surveillance are 3980 V and 4340 V and 59.2 Hz and 60.8 Hz, respectively, which are equivalent to 4160 V ± 4.33% and 60 Hz ± 1.33%. The maximum loading conditions associated with the voltage and frequency limits must be bounded by this Surveillance in order to verify that the steady-state loading of the Class 1E 4.16-kV ESF buses under maximum voltage (4340 V) and frequency (60.8 Hz) conditions following a postulated DBA does not exceed the Safety Guide 9 (Ref. 3) Regulatory Position C.2 limit for predicted loads, which includes derating the diesel generators due to temperature effects.

SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a Safety Injection signal without loss of offsite power. The emergency loads are the ESF loads.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

The requirement to verify the connection of permanent and autoconnected loads to the immediate access 230-kV offsite power system is intended to satisfactorily show the relationship of these loads to the DG loading logic. For a description of the permanent and auto-connected loads, refer to SR 3.8.1.11 Bases. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 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 3.8.1.12 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations of equal to or greater than 90°F but less than 175°F. 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 plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operating procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in MODES 3, 4, 5, or 6.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions are bypassed when the diesel engine trip cutout switch is in the cutout position and the DG is aligned for automatic operation. The noncritical trips include directional power, loss of field, breaker overcurrent, high jacket water temperature, and diesel overcrank. These noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

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

SR 3.8.1.14

This surveillance is in response to Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(3) requirements to demonstrate full-load-carrying capability for an interval of not less than 24 hours, of which 22 hours should be at a load equivalent to the continuous rating of the diesel generator and 2 hours at a load equivalent to the 2-hour rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR. SR 3.8.1.14 verifies that the cooling system functions within design limits in accordance with Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(3). The manufacturer's recommendation for the jacket water temperature is less than 185°F and for the lube oil temperature is less than 195°F.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

SR 3.8.1.14 contains test loading criterion of 2860 kW (nominal), which is the 2-hour out of 24 hours rating less instrument uncertainty, a test band, and DG derating. This criterion will load the DG to as near to the 2-hour rating as practical without exceeding the DG rating and will demonstrate that the DGs have adequate endurance and margin at a test load greater than the maximum expected steady-state load at worst-case conditions of voltage and frequency. The 2-hour test load, which is less than the DG 2-hour rating, is an exception to Regulatory Guide 1.108, Regulatory Position C.2.a.(3) (Ref. 9).

SR 3.8.1.14 contains a test loading criterion of 2750 kW (nominal) for the remaining 22-hour portion of the DG 24-hour full-load-carrying capability test. This criterion will load the DG at a load greater than the calculated worst-case maximum steady load up to the 2000- hour/year rating. The 22-hour test load, which is greater than the DG continuous rating, complies with Regulatory Guide 1.108, Regulatory Position C.2.a.(3) (Ref. 9).

The minimum loading for this Surveillance demonstrates that the DGs can run continuously at a load greater than the maximum expected steady-state load at the worst-case conditions of voltage and frequency. The load criteria are established to avoid exceeding vendor ratings.

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 3.8.1.14 (continued)

This Surveillance is modified by Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Note 2 ensures that the DGs are tested under load conditions that are as close to design basis conditions as practicable.

Administrative controls for performing this SR in MODES 1 or 2, with the DG paralleled to an offsite power supply, ensure or require that:

a. Weather conditions are conducive to performing this SR.

b. The offsite power supply and switchyard conditions support performing this SR, including communicating with the transmission group responsible for the 230-kV and 500-kV switchyards to ensure that, during the DG testing, vehicle access to these switchyards is controlled and no elective maintenance or testing on the offsite power sources is performed potentially affecting:

   - 230-kV and 500-kV systems (Exceptions are to be authorized by Operations Management)
   - Either units' 12-kV startup bus
   - Transformers or insulators

c. No equipment or systems assumed to be available for supporting the performance of the SR are removed from service.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve minimum required voltage and frequency within 10 seconds. SR 3.8.1.15 is in response to Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(5) requirements to demonstrate functional capability at full-load temperature conditions. SR 3.8.1.15 is an approved exception to Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(5) in that the test does not fully comply with the regulation. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis accident. SR 3.8.1.15 requires the DG achieves steady state voltage and frequency within limits.

The specified minimum and maximum steady-state voltages and frequencies for this Surveillance are 3980 V and 4340 V and 59.2 Hz and 60.8 Hz, respectively, which are equivalent to 4160 V ± 4.33% and 60 Hz ± 1.33%. The maximum loading conditions associated with the voltage and frequency limits must be bounded by this Surveillance in order to verify that the steady-state loading of the Class 1E 4.16-kV ESF buses under maximum voltage (4340 V) and frequency (60.8 Hz) conditions following a postulated DBA does not exceed the Safety Guide 9 (Ref. 3) Regulatory Position C.2 limit for predicted loads, which includes derating the diesel generators due to temperature effects.

Actual steady state operation is expected to achieve a level of stability closer to the nominal 60 Hz value. 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 requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on test data and manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto close signal on bus undervoltage, and the load sequencing timers are reset.

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 3.8.1.16 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operating procedures that are available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in MODES 5 or 6.

SR 3.8.1.17

SR 3.8.1.17 satisfies Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.a.(8) by demonstrating that the capability of the diesel generator unit to supply emergency power within the required time is not impaired during periodic testing.

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing. A Safety Injection signal, received while the DG is operating in a test mode, results in the auxiliary breaker opening and the emergency loads automatically sequencing onto the DG.

In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 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 plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operating procedures that are available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in Modes 5 or 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by load sequencer timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The load sequence time interval tolerances ensure that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. The timing limits for the load sequence timers are found in table B3.8.1-1 (ESF Timers) and table B3.8.1-2 (Auto transfer Timers).

With an ESF timer found to be outside the range of acceptable settings, the corresponding DG shall be declared inoperable in MODES 1, 2, 3, and 4, and the corresponding CONDITION followed. With an Auto Transfer timer found to be outside the range of acceptable settings, the corresponding DG shall be declared inoperable for all MODES. This action is necessary only for that time required to open the breaker on the affected load.

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 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operating procedures that are available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in MODES 5 or 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

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

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with a Safety Injection signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

This Surveillance was established based upon NUREG-1431, Volume 1, Revision 1 (Ref. 15) and Regulatory Guide 1.9, Revision 3, which includes a combined Safety Injection Actuation Signal (SIAS) and Loss of Offsite Power (LOOP) Test. DCPP is not committed to Regulatory Guide 1.9, Revision 3. This test is not required by Regulatory Guide 1.108, Revision 1 (Ref. 9).

The specified minimum and maximum steady state voltages and frequencies for this Surveillance are 3980 V and 4340 V and 59.2 Hz and 60.8 Hz, respectively, which are equivalent to 4160 V ± 4.33% and 60 Hz ± 1.33%. The maximum loading conditions associated with the voltage and frequency limits must be bounded by this Surveillance in order to verify that the steady-state loading of the Class 1E 4.16-kV ESF buses under maximum voltage (4340 V) and frequency (60.8 Hz) conditions following a postulated DBA do not exceed the Safety Guide 9 (Ref. 3) Regulatory Position C.2 limit for predicted loads, which includes derating the diesel generators due to temperature effects.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations for DGs of equal to or greater than 90°F but less than 175°F. 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 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 plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operating procedures that are available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Preplanned maintenance that would require the performance of this SR to demonstrate operability following the maintenance shall only be performed in MODES 5 or 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. This Surveillance satisfies the Regulatory Guide 1.108 (Ref. 9), Regulatory Position C.2.b. requirement to start the redundant DG units simultaneously to help identify certain common failure modes undetected in single DG unit tests. Also, this Surveillance demonstrates that each DG can achieve minimum required voltage and frequency within the specified time when the DGs are started simultaneously.

The specified minimum and maximum steady-state voltages and frequencies for this Surveillance are 3980 V and 4340 V and 59.2 Hz and 60.8 Hz, respectively, which are equivalent to 4160 V ± 4.33% and 60 Hz ± 1.33%. The maximum loading conditions associated with the voltage and frequency limits must be bounded by this Surveillance in order to verify that the steady-state loading of the Class 1E 4.16-kV ESF buses under maximum voltage (4340 V) and frequency (60.8 Hz) conditions following a postulated DBA does not exceed the Safety Guide 9, March 1971 (Ref. 3) Regulatory Position C.2 limit for predicted loads, which includes derating the diesel generators due to temperature effects.

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 DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations of equal to or greater than 90°F but less than 175°F.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Safety Guide 9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 1971.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. NUREG-1151, "Technical Specifications Diablo Canyon Nuclear Power Plant, Units 1 and 2," August 1985. (TS Bases 3/4.8.1, 3/4.8.2, 3/4.8.3).
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, Rev. 1, Oct 1979.
11. ASME, Boiler and Pressure Vessel Code, Section XI.
12. Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators," May 31, 1994.
13. Diesel Generator Allowed Outage Time Study, LA 44/43, October 4, 1989
14. License Amendment 44/43, October 4, 1989.
15. NUREG-1431, Revision 1 “Standard Technical Specifications Westinghouse Plants,” dated April 1995.
16. Not Used

(continued)

BASES

REFERENCES (continued)

17. License Amendment 166/167, April 20, 2004.

18. Calculation PRA 02-06, "Diesel Generator LAR for 14-day AOT."

19. License Amendment 174/176, September 28, 2004.

20. Operating Procedure OP J-2:VIII, "Guidelines for Reliable Transmission Service for DCPP."

21. ANSI C84.1-1977, “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60 Hz)”

22. PG&E Letter DCL-98-180, "License Amendment Request 97-09, 'Technical Specification Conversion,' Response to Request for Additional Information for Section 3.8," dated December 17, 1998

23. SAP Notification DA 50704110, SR 3.8.1.6 Missed Surveillance, May 2015

24. PG&E Letter DCL-14-018, License Amendment Request 14-01, “Revision to Technical Specifications 3.8.1, 'AC Sources – Operating,'” dated March 27, 2014

25. NRC SER for License Amendments 218 and 220, transmitted via letter to PG&E dated July 1, 2015

26. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010

27. License Amendment 74/73, August 12, 1992

28. PG&E Letter DCL-92-036, "License Amendment Request 92-03, Revision of Technical Specifications 3/4.8.1 and 3/4.8.2, Increase Emergency Diesel Generator Fuel Oil Storage Requirements," dated February 14, 1992

TABLE B 3.8.1-1
LOAD SEQUENCING TIMERS
ESF TIMERS

			TIMER SETTINGS (sec)		
		COMPONENT	MINIMUM	NOMINAL	MAXIMUM
1.	Bus F	Centrifugal Charging Pump No. 1	1.5	2	3
		Safety Injection Pump No. 1	5	6	7
		Component Cooling Water Pump No. 1	9	10	11
		Auxiliary Saltwater Pump No. 1	13	14	15
		Containment Fan Cooler Unit No. 2	17	18	19
		Containment Fan Cooler Unit No. 1	20.8	22	23.2
		Auxiliary Feedwater Pump No. 3	24.5	26	28
2.	Bus G	Centrifugal Charging Pump No. 2	1.5	2	3
		Residual Heat Removal Pump No. 1	5	6	7.5
		Component Cooling Water Pump No. 2	9	10	11
		Auxiliary Saltwater Pump No. 2	13	14	15
		Containment Fan Cooler Unit No. 3	17	18	19
		Containment Fan Cooler Unit No. 5	20.8	22	23.2
		Containment Spray Pump No. 1	24.5	26	28
3.	Bus H	Safety Injection Pump No. 2	1	2	3
		Residual Heat Removal Pump No. 2	5	6	7
		Component Cooling Water Pump No. 3	12.5	14	15
		Auxiliary Feedwater Pump No. 2	17	18	19.5
		Containment Fan Cooler Unit No. 4	20.8	22	23.2
		Containment Spray Pump No. 2	24.5	26	28

TABLE B 3.8.1-2
LOAD SEQUENCING TIMERS
AUTO TRANSFER TIMERS

		COMPONENT	TIMER SETTINGS (sec) MINIMUM	NOMINAL	MAXIMUM
1.	Bus F	Component Cooling Water Pump No. 1	4	5	6
		Auxiliary Saltwater Pump No. 1	9	10	11
		Auxiliary Feedwater Pump No. 3	13	14	15
		Centrifugal Charging Pump No. 1	18.5	20	21.5
		Containment Fan Cooler Unit No. 1	23.5	25	27
		Containment Fan Cooler Unit No. 2	23.5	25	27
2.	Bus G	Component Cooling Water Pump No. 2	4	5	6
		Auxiliary Saltwater Pump No. 2	9	10	11
		Centrifugal Charging Pump No. 2	18.5	20	21.5
		Containment Fan Cooler Unit No. 3	23.5	25	27
		Containment Fan Cooler Unit No. 5	23.5	25	27
3.	Bus H	Component Cooling Water Pump No. 3	4	5	6
		Auxiliary Feedwater Pump No. 2	13	14	15
		Containment Fan Cooler Unit No. 4	22	25	27

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 accidents involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems. During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted, provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on: a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both. c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems. d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event. In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power. The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems — Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with the Class 1E AC electrical power distribution subsystem required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving 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. The Unit 1 Offsite Circuit #1 consists of Startup Transformer 1-1 supplied from the immediate access 230-kV Switchyard power source, which feeds Startup Transformer 1-2 through series supply breakers 52VU12 and 52VU14. Startup Transformer 1-2 then supplies power through breaker 52HG15 to each Class 1E bus feeder breaker (Bus F - 52HF14, Bus G - 52HG14, Bus H - 52HH14). The Unit 1 Offsite Circuit #2 is the delayed access 500-kV circuit which becomes available only after opening the motor operated disconnect to the main

(continued)

BASES

LCO (continued)	generator. This circuit consists of Auxiliary Transformer 1-2 supplied from the 500-kV Switchyard through the main bank transformers. Auxiliary Transformer 1-2 supplies power directly to each of the Class 1E bus feeder breakers (Bus F - 52HF13, Bus G - 52HG13, Bus H - 52HH13). The Unit 2 Offsite Circuit #1 consists of Startup Transformer 2-1 supplied from the immediate access 230-kV Switchyard power source, which feeds Startup Transformer 2-2 through series supply breakers 52VU23 and 52VU24. Startup Transformer 2-2 then supplies power through breaker 52HG15 to each Class 1E bus feeder breaker (Bus F - 52HF14, Bus G - 52HG14, Bus H - 52HH14). The Unit 2 Offsite Circuit #2 is a delayed access circuit which only becomes available after opening the motor operated disconnect to the main generator. This circuit consists of Auxiliary Transformer 2-2 supplied from the 500-kV Switchyard through the main bank transformers. Auxiliary Transformer 2-2 supplies power directly to each of the Class 1E bus feeder breakers (Bus F - 52HF13, Bus G - 52HG13, Bus H -3 52HH13). Operating Procedure OP J-2:VIII (Ref. 20) provides guidelines for determining the operability of the 230-kV and 500-kV offsite power sources based on existing grid and plant conditions. The DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. With administrative controls in place, it is acceptable for Class 1E AC electrical power distribution subsystems to be cross tied during shutdown conditions, allowing a single offsite power circuit or a single DG to supply the required Class 1E AC electrical power distribution subsystems. The two redundant diesel fuel oil transfer pumps supply fuel oil to DG day tanks from either storage tank. One pump is adequate to supply the six DGs operating at full load. Only one train is required to be OPERABLE in MODES 5 or 6.
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 are available; c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

(continued)

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

A.1

An offsite circuit would be considered inoperable if it were not available to the required Class 1E bus(es). If two Class 1E AC electrical power distribution subsystems are required by LCO 3.8.10, and one Class 1E AC electrical power distribution subsystem has offsite power available, the remaining Class 1E AC electrical power distribution subsystem 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 inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required AC electrical power distribution subsystems , the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of 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 that 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.

(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)

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not an AC electrical power distribution subsystem is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized AC electrical power distribution subsystem.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 lists the SRs from LCO 3.8.1 that are applicable 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 3.8.1.12, SR 3.8.1.13, SR 3.8.1.18 (for ESF timers), and SR 3.8.1.19 are excepted because SI response functions are not required to be OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required with the DG that is not required to be OPERABLE.

This SR is modified by a Note listing the applicable SRs from LCO 3.8.1 that are not required to be performed. The reason for the Note is to preclude requiring the OPERABLE DG from being paralleled with the offsite power network or otherwise rendered inoperable during performance of an SR. The Note would also preclude deenergizing a required 4.16kV ESF bus or disconnecting a required offsite circuit for performance of an SR. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is required that these SRs must be current. However, actual performance of these SRs must not take place on the required OPERABLE DG as it must be declared inoperable when paralleled to any of its associated off-site power sources. Only perform these surveillances when the minimum required OPERABLE diesel can be maintained.

Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

1. License Amendment 184/186, January 3, 2006.
2. Operating Procedure OP J-2:VIII, "Guidelines for Reliable Transmission Service for DCPP."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, Starting Air, and Turbocharger Air Assist

BASES

BACKGROUND

The diesel fuel oil storage system consists of two common tanks with a nominal capacity of 50,000 gallons each. The TS-required fuel oil quantity is based on the calculated fuel oil consumption necessary to support the operation of the DGs to power the minimum engineered safety feature (ESF) systems required to mitigate a design basis accident (LOCA) in one unit and those minimum required systems for a concurrent non-LOCA safe shutdown in the remaining unit (both units initially in MODE 1 operation). The fuel oil consumption is calculated for a period of 7 days operation of minimum ESF systems. This requirement provides a sufficient operating period within which offsite power can be restored and/or additional fuel can be delivered to the site.

Fuel oil is transferred from the storage tanks via the diesel fuel oil storage and transfer system to replenish the day tanks as required. The design incorporates sufficient redundancy so that a malfunction of either an active or a passive component will not impair the ability of the system to supply fuel oil. Two redundant fuel oil transfer pumps supply fuel oil to DG day tanks from either storage tank. One pump is adequate to supply the six DGs operating at full load. Each DG tank has two separate, redundant transfer pump start-stop level switches. Each level switch automatically starts a transfer pump and opens the supply header solenoid valve corresponding to the respective transfer pump, 0-1 or 0-2. In addition, high and low level alarms are provided on each day tank and activate alarms both locally and in the control room.

Fuel is transferred to each day tank via two level control valves (and two associated upstream isolation valves) per DG. Each of the two level control valves and associated upstream isolation valves on each DG is associated with a separate diesel fuel oil transfer system train; however, the level control valves, the isolation valves immediately upstream from the level control valves, and the day tank are part of the associated DG rather than the diesel fuel oil transfer system. The air supply to each of the two level control valves to the same DG is from its associated air receiver. Cross-tie capability allows the air supply of both level control valves to come from the same air receiver. Under this circumstance, the associated DG is still considered OPERABLE.

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BASES

BACKGROUND (continued)

The diesel lube oil storage requirement is based upon a conservative usage factor of 1% of fuel oil consumption. The storage system used to meet this requirement is that located in the warehouse where 650 gallons of lube oil is stored in drums. This storage is augmented by a second storage location within the diesel engine itself. The lube oil level on each engine's dip stick is maintained 5 inches above the engine's operability limit. This provides approximately 120 gallons of usable lube oil within each of the 6 diesel engines.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by 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.

The DG fuel oil consumption is calculated for a period of 7 days operation of minimum ESF systems. This requirement provides a sufficient operating period within which offsite power can be restored and/or additional fuel can be delivered to the site.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. The total engine oil sump inventory (all engines) is capable of supporting a minimum of 7 days of operation at minimum ESF loads. The onsite storage inventory (warehouse) is in addition to the engine oil sump and is also sufficient to ensure 7 days of continuous operation. These supplies are sufficient to allow the operators to replenish lube oil from outside sources as a third resource.

Each DG has two redundant 100% capacity air start systems and a turbocharger air assist system with adequate capacity for three successive start attempts each on the DG without recharging the air start receivers or the turbocharger air assist air receiver.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS	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 Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems. Since diesel fuel oil, lube oil, air start, and turbocharger air assist subsystems 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 minimum ESF systems operation. The required combined stored diesel fuel oil is a contained quantity with different storage requirements for unit operation in MODE 1, 2, 3, and 4 and for MODE 5 and 6. With both units operating in MODE 1, 2, 3, and 4, the required level is ≥ 79,000 gallons. With one unit operating in MODE 1, 2, 3, or 4, and the other unit in MODE 5 or 6, the required fuel oil level is 41,000 gallons plus 31,000 gallons, for a total of 72,000 gallons combined storage. With both units in MODE 5 or 6, the required fuel oil level is 62,000 gallons. The required combined stored fuel oil was revised by License Amendments 74 and 181 for Unit 1 and 73 and 183 for Unit 2.

(continued)

BASES

LCO (continued)

The Note permits diesel fuel oil storage tank cleaning to be performed. Conducting the cleaning requires the tank to be taken out of service. For this infrequent event, the inventory in the remaining tank is sufficient to support operation of the DGs to power the minimum required loads to maintain safe conditions for a period of 4 days, considering one unit in MODE 1, 2, 3, 4, 5, or 6 and one unit in MODE 6 with 23 feet of water above the reactor vessel flange or with the reactor vessel defueled. The requirements for diesel fuel oil tank cleaning were approved by License Amendment 74 for Unit 1 and 73 for Unit 2. Refer to FSAR Section 9, *Auxiliary Systems*, for discussion associated with tests and inspections of the Diesel Fuel Oil and Transfer System.

The fuel oil is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources-Shutdown."

The starting air system and turbocharger air assist system are required to have a minimum capacity for three successive DG start attempts without recharging the air start receivers or the turbocharger air assist air receiver.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, starting air, and turbocharger air assist subsystems support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, starting air, and turbocharger air assist are required to be within limits when the associated DGs are required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG or diesel fuel oil storage tank, except for Condition A. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

(continued)

BASES

ACTIONS (continued)

Condition A is excepted from this allowance for diesel fuel oil storage tanks, since the requirement is for a combined storage quantity contained in both storage tanks. However, the Note would still allow separate Condition entry into a DG subsystem's Required Action coincident with Condition A.

A.1 and A.2

In this Condition, the 7 day fuel oil supply for the DGs is not available. 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 associated DGs 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. Should the specified 6 day fuel oil supply for both units not be available, but the available supply is still greater than that required to support operation of one unit, then that available supply can be allocated to a selected unit, and the DGs declared inoperable under Action H need only be the ones associated with the unit that has the inadequate supply.

B.1

With diesel engine lube oil stored inventory < 650 gal, sufficient lubricating oil is available to support 7 days of continuous DG operation based on minimum 7 day ESF systems loading at 1% of fuel oil consumption. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply of 610 gallons. This ACTION should be entered based upon warehouse inventory of less then 650 gallons with both units in MODES 1, 2, 3 or 4 and less then 590 gallons with one unit in MODES 1, 2, 3, or 4 and the other in MODES 5 or 6. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), 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 DGs inoperable. The 7 day Completion Time allows for further evaluation, re-sampling and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

E.1

With both starting air receiver pressures < 180 psig, sufficient capacity for three successive DG start attempts does not exist. However, as long as one receiver pressure is > 150 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while one air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With turbocharger air assist air receiver pressure < 180 psig, sufficient capacity for three successive DG start attempts does not exist. However, as long as the receiver pressure is > 150 psig, there is

(continued)

BASES

ACTIONS

F.1 (continued)

adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the turbo air assist air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

G.1

With a Required Action and associated Completion Time or Conditions E or F not met, or one or more DG's starting air, or turbocharger air assist subsystem not within limits for reasons other than addressed by Conditions E or F, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

H.1, H.2, and H.3

With a Required Action and associated Completion Time not met, or the fuel oil storage tanks not within limits for reasons other than addressed by Conditions A, B, C, or D, the fuel oil storage tanks may be incapable of supporting the DGs in performing their intended function. This condition requires declaring inoperable, all the DGs on the unit(s) associated with either the inadequate fuel oil inventory, the fuel storage tank(s) having particulate outside the limit, and/or the fuel storage tank(s) having properties outside limits; and shutting down to MODE 3 in 6 hours and MODE 5 in 36 hours any associated unit(s) operating in MODE 1,2,3,or 4.

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 DG operation for 7 days based on a realistic (minimum) ESF systems loading profile. 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

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of operation for each DG at minimum ESF systems loading. The 650 gal requirement is based on the DG

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

manufacturer consumption values for the run time of the DG at 1% of fuel oil consumption. The storage system used to meet this requirement is that located within the warehouse where 650 gallons of lube oil is stored in drums.

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

SR 3.8.3.3

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 tanks. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-81 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-81 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.82 and ≤ 0.89 or an API gravity at 60°F of ≥ 27° and ≤ 42°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176 or a water and sediment content of ≤ 0.05 volume percent when tested in accordance with ASTM D-1796-83 or ASTM D-2709-96 (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-81 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-81 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 (Ref. 6) or ASTM D2622-82 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

If the analysis of the new fuel oil sample indicates that one or more of the other properties specified in Table 1 of ASTM D975-81 are not within limits, then Required Action D.1 shall be entered, allowing 31 days to restore fuel oil properties to within limits.

Fuel oil degradation during long term storage shows up as an increase in particulates, due mostly to oxidation. The presence of particulates does not mean the fuel oil will not burn properly in a diesel engine. The particulates can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-78, Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentrations 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 must be considered and tested separately.

ASTM D 2276-78 was written specifically for aviation fuel. However, it is used in this SR to evaluate diesel fuel oil. Therefore, it may be necessary to perform this test as a modified method. For example, a 500 ml sample may be analyzed rather than a one gallon sample.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of three engine start cycles without recharging. Each start cycle is 15 seconds of cranking. The pressure specified in this SR is intended to reflect the lowest value at which three starts 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 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks eliminates the necessary environment for bacterial survival. This is the most effective

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.8.3.5 (continued) means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, or 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. This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance. SR 3.8.3.6 This Surveillance ensures that, without the aid of the refill compressor, sufficient turbocharger air assist air receiver capacity for each DG is available. The system design requirements provide for a minimum of three engine start cycles without recharging. Each start cycle is 15 seconds of cranking. The pressure specified in this SR is intended to reflect the lowest value at which three starts 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.
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. 6. ASTM Standards: D4057-81; D975-81; D4176-82; D1796-83; D1552-79; D2622-82; D2276-78, Method A; D2709-96. 7. ASTM Standards, D975, Table 1. 8. ASME, Boiler and Presser Vessel Code, Section XI. 9. License Amendment 74/73, August 12, 1992. 10. License Amendment 181/183, May 25, 2005. 11. AR A0566159, AR A0512756, AR A0504056.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources-Operating

BASES

BACKGROUND

The Class 1E DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected PG&E Design Class I equipment and backup 120-Vac Class 1E bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the Class 1E 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, March 1971 (Ref. 2) and IEEE-308 (Ref. 3).

The 125-Vdc- electrical power system consists of three independent Class 1E DC electrical power subsystems. Each subsystem consists of one 60-cell 125-Vdc battery (Batteries 11(21), 12 (22), and 13 (23)), the dedicated battery charger and backup charger for each battery, and all the associated switchgear, control equipment, and interconnecting cabling. Although the three 125-Vdc batteries consist of a 60-cell configuration, analysis is in place to fully support a 59-cell configuration (Ref. 11). Bases information in B 3.8.4, B 3.8.5, and B 3.8.6 are written for a 60-cell battery and can be adjusted on a volts per cell basis for a 59-cell battery.

There are two backup chargers for the three Class 1E DC subsystems. One backup charger is shared between two Class 1E DC subsystems. The other backup charger is dedicated to the third Class 1E DC subsystem. The backup chargers provide backup service in the event that the dedicated battery charger is out of service. If the backup battery charger is substituted for one of the dedicated battery chargers, then the requirements of independence and redundancy between subsystems are not maintained, and operation in this condition is limited to 14 days by Condition D.

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 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 are backup sources to power the 120-Vac Class 1E buses.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System-Operating," and LCO 3.8.10, "Distribution Systems-Shutdown."

(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.

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in the UFSAR, Chapter 8 (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for the three DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage limit is 112.1V for a 59-cell battery.

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 125 V for a 60 cell battery (i.e., cell voltage of 2.06 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.06 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage range of 2.20 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The float voltage range of 2.20 to 2.25 Vpc corresponds to a total float voltage output range of 132.0 through 135.0 V for a 60 cell battery.

Each DC electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient excess capacity to restore the battery from the design minimum charge to its fully charged state within 12 hours while supplying normal steady state loads discussed in the UFSAR, Chapter 8 (Ref. 4).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

(continued)

`BASES

BACKGROUND (continued)	When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 5), and in the UFSAR, Chapter 15 (Ref. 6), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of: a. An assumed loss of all offsite AC power or all onsite AC power; and b. A worst case single failure. The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO	The DC electrical power subsystems, each subsystem consisting of one battery, battery charger for each battery and the corresponding control equipment and interconnecting cabling supplying power to the associated bus are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any one DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4). An OPERABLE DC electrical power subsystem requires the battery and its normal or backup charger to be operating and connected to the associated DC bus.
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 PG&E Design Class I functions are maintained in the event of a postulated DBA. The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."
ACTIONS	<u>A.1, A.2, and A.3</u> Condition A represents one DC electrical power subsystem with one dedicated battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the dedicated charger to OPERABLE status or providing an alternate means of restoring the associated battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

(continued)

BASES

ACTIONS (continued)

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to 2 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the 12 hour period the battery float current is not less than or equal to 2 amps this indicates there may be additional battery problems and the battery must be declared inoperable in accordance with LCO 3.8.6 Required Action B.2.

Required Action A.3 limits the restoration time for the inoperable dedicated battery charger to 14 days. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., backup charger or non-Class 1E battery charger). The 14 day completion time reflects a reasonable time to effect restoration of the dedicated battery charger to operable status.

(continued)

BASES

ACTIONS (continued)

B.1

Condition B represents one DC electrical power subsystem with one battery inoperable. With one battery inoperable, the DC bus is being supplied by the associated OPERABLE battery charger. Any event that results in a loss of the associated 480-V Class 1E bus supporting the normal battery charger will also result in loss of or degraded DC to the associated DC electrical power subsystem. Recovery of the 480-V Class 1E bus, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., diesel generator control and field flash, AC load shed and diesel generator output circuit breakers, etc.) likely rely upon the battery. In addition, the energization transients of any DC loads that are beyond the capability of the battery charger and normally require the assistance of the battery will not be able to be brought online. The 2 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C represents one Class 1E DC electrical power subsystem and associated ESF equipment 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 subsystem. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution subsystem. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

If one of the required DC electrical power subsystems is inoperable for reasons other than Condition A or B (e.g., inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of the minimum necessary DC electrical power subsystems to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time 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 (Ref. 7).

D.1

The design of the 125-Vdc electrical power distribution system is such that a battery can have associated with it a dedicated full capacity charger powered from its associated 480-V Class 1E bus or a backup full capacity charger powered from another 480-V Class 1E bus. Use of the backup full capacity charger results in more than one full capacity charger receiving power simultaneously from a single 480-V Class 1E bus and causes the requirements of independence and redundancy between subsystems to no longer be maintained. Thus, operation with two chargers powered by the same vital bus is limited to 14 days.

(continued)

BASES

ACTIONS (continued)

E.1 and E.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 overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 12). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 12, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action E.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

The minimum established float voltage provided by the battery manufacturer is 2.17 Vpc or 130.2 V at the battery terminals for a 60-cell battery. This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state, while supplying the continuous steady state loads of the associated DC electrical power subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. 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 (continued)

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Safety Guide 32, August 1972 (Ref. 9), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 400 amps at the minimum established float voltage for greater than 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest combined demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ 2 amps.

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 (continued)	<u>SR 3.8.4.3</u> A 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 UFSAR Chapter 8, (Ref. 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 two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test. The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Safety Guide 6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," March, 1971.
3. IEEE Std. 308-1971.
4. UFSAR, Chapter 8.
5. UFSAR, Chapter 6.
6. UFSAR, Chapter 15.
7. NUREG-1151, "Technical Specifications Diablo Canyon Nuclear Power Plant, Units 1 and 2," August 1985. (TS Bases 3/4.8.1, 3/4.8.2, 3/4.8.3).
8. IEEE Std. 450-1995.
9. Safety Guide 32, "Use of IEEE Std 308-1971, 'Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations,'" August 1972.
10. Not used.
11. Electrical Design Calculations 235A-DC thru 235F-DC.
12. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

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 diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of 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 recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The DC electrical power subsystems, each subsystem consisting of one battery, one battery charger per battery, and the corresponding control equipment and interconnecting class 1E cabling within the subsystem, are required to be OPERABLE to support required trains of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems-Shutdown." An OPERABLE subsystem consists of a DC bus connected to a battery with an OPERABLE battery charger which is fed from an OPERABLE AC Class 1E bus (Ref B.3.8.10).

(continued)

BASES

LCO (continued)	With administrative controls in place, DC buses may be cross-tied when a battery is taken out for maintenance provided that the battery and the Class 1E cross-tie has sufficient capacity and protection for its own loads and the cross-tie loads. The resulting circuit is not required to be single failure resistant. 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 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 irradiated fuel assemblies in the core; b. Required features needed to mitigate a fuel handling accident involving handling recently irradiated fuel are available; c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition. The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.
ACTIONS	<u>A.1, A.2.1, A.2.2, A.2.3, and A.2.4</u> One or more required DC electrical power subsystems may be inoperable provided that the remaining OPERABLE DC electrical power subsystem(s) support the DC electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems - Shutdown," and are capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and recently irradiated fuel movement. By allowing the option to declare affected 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. A required feature is not affected if sufficient power is provided by the associated DC power source such that the feature is capable of performing its specified safety function(s). An engineering evaluation may be required to determine if a required feature is affected.

(continued)

BASES

ACTIONS	<u>A.1, A.2.1, A.2.2, A.2.3, and A.2.4</u> (continued) For example, refer to references 3 and 4. 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 that 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.
SURVEILLANCE REQUIREMENTS	<u>SR 3.8.5.1</u> SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, refer to the corresponding Bases for LCO 3.8.4 for a discussion of each SR. This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of an SR. This note does not except the requirement for the battery to be capable of performing the particular function, just that the capability need not be demonstrated while that source of power is being relied on to meet the LCO.

(continued)

BASES (continued)

REFERENCES	1.	UFSAR, Chapter 6.
	2.	UFSAR, Chapter 15.
	3.	DCM S-67, "125V/250V Direct Current System, Section 4.3.1."
	4.	AR A0456369
	5.	License Amendment 184/186, January 3, 2006.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND	This LCO delineates the limits on battery float current as well as electrolyte temperature, level, and float voltage for the DC electrical power subsystem batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources - Operating," and LCO 3.8.5, "DC Sources - Shutdown." In addition to the limitations of this Specification, the Battery Monitoring and Maintenance Program also implements a program specified in Specification 5.5.17 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450, "IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead-Acid Batteries For Stationary Applications" (Ref. 3). The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215**.** This specific gravity corresponds to an open circuit battery voltage of approximately 125 V for a 60 cell battery (i.e., cell voltage of 2.06 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.06 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturing instructions. Optimal long term performance however, is obtained by maintaining a float voltage range of 2.20 to 2.25 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge. The float voltage range of 2.20 to 2.25 Vpc corresponds to a total float voltage output range of 132.0 through 135.0 V for a 60 cell battery.
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 diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the required DC electrical power subsystem(s) OPERABLE during accident conditions, in the event of: a. An assumed loss of all offsite AC power or all onsite AC power; and b. A worst case single failure. Battery parameters satisfy the Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO	Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventive maintenance, testing, and monitoring performed in accordance with the Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.17.
APPLICABILITY	The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery OPERABILITY 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	<u>A.1, A.2, and A.3</u> With one or more cells in one battery < 2.07 V, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells < 2.07 V, and continued operation is permitted for a limited period up to 24 hours. Since the Required Actions only specify “perform,” a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Conditions(s), depending on the cause of the failure, is entered. If SR 3.8.6.1 is failed when in Condition A, then there is not assurance that there is still sufficient battery capacity to perform the intended function. In this case the battery must be declared inoperable and Condition F must be entered.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

A battery with float current > 2 amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addressed charger inoperability. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than 2.07 V, the associated "OR" statement in Condition F is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.07 V there is good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to temporary loss of the battery charger. A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

(continued)

BASES

ACTIONS (continued)

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 12 hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies “perform,” a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

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

With one battery with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.17, Battery Monitoring and Maintenance Program). They are modified by a note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.17.b item to initiate action to equalize and test in accordance with manufacturer’s recommendation are taken from Annex D of IEEE Standard 450 (Ref. 3). They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer’s recommended testing the battery may have to be declared inoperable and the affected cells(s) replaced.

(continued)

BASES

ACTIONS (continued)

D.1

With a battery with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limit. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

E.1

With two or more batteries in redundant DC electrical power subsystems with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform there required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in total loss of function on multiple systems that rely upon the batteries. The longer completion times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one DC electrical power subsystem within 2 hours.

F.1

With one battery with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, or E, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC battery must be declared inoperable. Additionally, discovering a battery with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 3). The Surveillance Frequency is 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 float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 Action A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established float voltage provided by the battery manufacturer, which corresponds to 130.2 V for 60 cells at the battery terminals, or 2.17 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in the range of less than 2.13 Vpc, but greater than 2.07 Vpc, are addressed in Specification 5.5.17. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 V. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.3

The electrolyte level minimum established design limit is the manufacturer minimum level indication mark on the battery case. The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. 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 (continued)

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e. 60°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

A modified 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 often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test. The modified performance discharge test and service test should be performed in accordance with IEEE-450 (Ref. 3).

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 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 3) 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. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit.

The Surveillance Frequency is 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 service life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 24 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 3), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is < 90% of the manufacturer's rating. The Surveillance Frequency basis is consistent with IEEE-450 (Ref. 3), except if accelerated testing is required, it will be performed at a 24-month frequency to coincide with a refueling outage.

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.

REFERENCES

1. UFSAR, Chapter 6
2. UFSAR, Chapter 15
3. IEEE Std. 450-1995
4. UFSAR, Chapter 8
5. IEEE Std. 485-1983

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND	The Class 1E UPS inverters are the preferred source of power for the AC Class 1E buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the Class 1E buses. The inverters can be powered from an internal AC source/rectifier or from the station battery. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in the UFSAR, Chapter 7 (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 RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems. The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required AC Class 1E 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).
LCO	The Class 1E UPS 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.

(continued)

BASES

LCO (continued)	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 ensure an uninterruptible supply of AC electrical power to the 120-Vac Class 1E buses even if the 4.16-kV safety buses are de-energized. Operable inverters require the associated 120-Vac Class 1E 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 an internal AC source via rectifier as long as the station battery is available as the uninterruptible power supply.
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 PG&E Design Class I 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	<u>A.1</u> With a required inverter inoperable, its associated 120-Vac Class 1E bus becomes inoperable until it is re-energized from its Class 1E 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 120-Vac bus is re-energized within 2 hours. Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the 120-Vac Class 1E bus is powered from its constant voltage source, it is relying upon interruptible

(continued)

BASES

ACTIONS

A.1 (continued)

AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the 120-Vac Class 1E buses is the preferred source for powering instrumentation trip setpoint devices.

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.8.7.1 This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and 120-Vac Class 1E buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC Class 1E 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 7. 2. UFSAR, Chapter 6. 3. UFSAR, Chapter 15. 4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

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 Class 1E UPS inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum inverters to each 120-Vac Class 1E bus 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 available to mitigate events postulated during shutdown, such as a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, AC and DC inverters are only required to mitigate fuel handling accidents involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). 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	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).

(continued)

BASES (continued)

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 are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

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

One or more Class 1E UPS inverters may be inoperable provided that the remaining OPERABLE inverters support the Class 1E 120-Vac bus electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems - Shutdown," and 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 Class 1E UPS 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 that 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.

(continued)

BASES

ACTIONS	A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued) 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 Class 1E UPS inverters and to continue this action until restoration is accomplished in order to provide the necessary Class 1E UPS inverter power to the unit safety systems. The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a constant voltage source transformer.
SURVEILLANCE REQUIREMENTS	SR 3.8.8.1 This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC Class 1E 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 120-Vac Class 1E 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 3. License Amendment 184/186, January 3, 2006

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems-Operating

BASES

BACKGROUND

The onsite Class 1E electrical power distribution system is designed with three 4.16-kV and 480-V Class 1E buses (F, G, and H) and three 125-Vdc Class 1E buses. The plant protection system (PPS) is designed with four input channels (I, II, III, and IV) powered from four 120-Vac Class 1E buses (1, 2, 3, and 4). The four channels provide input to the solid state protection system (SSPS) Trains A and B. Each SSPS train actuates engineered safety feature (ESF) equipment in the three Class 1E AC and DC buses and certain non-PG&E Design Class I equipment in the non-Class 1E AC and DC buses.

There are three AC electrical power subsystems, each comprised of a primary ESF 4.16-kV bus and secondary 480-V and 120-Vac buses, distribution panels, motor control centers and load centers. Each 4.16-kV ESF bus has two separate and independent offsite sources of power as well as a dedicated onsite diesel generator (DG) source. Each 4.16-kV ESF bus is normally connected to the 500-kV offsite source. After a loss of this normal 500-kV offsite power source to a 4.16-kV ESF bus, a transfer to the alternate 230-kV offsite source is accomplished by utilizing a time delayed bus undervoltage relay. If all offsite sources are unavailable, the onsite emergency DG supplies power to the 4.16-kV ESF bus. Control power for the 4.16-kV 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 480-V electrical power distribution system for each bus includes the Class 1E motor control centers shown in Table B 3.8.9-1.

The 120-Vac Class 1E buses are arranged in four buses and are normally powered from the inverters. The alternate power supply for the 120-Vac Class 1E buses are Class 1E constant voltage source transformers powered from the same bus 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. In addition, each inverter can be powered from a bus other than its associated bus.

There are three independent 125-Vdc electrical power distribution subsystems (one for each bus).

The list of all required distribution buses is presented in Table B 3.8.9-1.

(continued)

BASES (continued)

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 Class 1E AC, DC, and 120-Vac 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 Class 1E AC, DC, and 120-Vac bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of: a. An assumed loss of all offsite power or all onsite AC electrical power; and b. A worst case single failure. The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of Class 1E AC, DC, and 120-Vac 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 Class 1E AC, DC, and 120-Vac bus electrical power distribution subsystems are required to be OPERABLE. Maintaining the Class 1E AC, DC, and 120-Vac 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 Class 1E AC electrical power distribution subsystems require the associated buses and motor control centers to be energized to their proper voltages. OPERABLE Class 1E DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE 120-Vac Class 1E bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage, inverter using internal AC source, or Class 1E constant voltage transformer.

(continued)

BASES

LCO (continued)	In addition, tie breakers between redundant Class 1E AC, DC, and 120-Vac 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, Class 1E redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16-kV buses from being powered from the same offsite circuit.
APPLICABILITY	The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that: a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and b. Adequate core cooling is provided, and containment OPERABILITY and other PG&E Design Class I 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	<u>A.1</u> With one required Class 1E AC electrical power subsystem inoperable, the remaining portions of the AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining portions of the power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required Class 1E AC buses, load centers, and motor control centers must be restored to OPERABLE status within 8 hours or in accordance with the Risk Informed Completion Time Program. Condition A worst scenario is one AC electrical power distribution subsystem without AC power (i.e., no offsite power to the 4.16-kV ESF bus and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining AC electrical power

(continued)

BASES

ACTIONS

A.1 (continued)

distribution subsystems by stabilizing the unit, and on restoring power to the affected subsystem. 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 subsystem, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the other AC electrical power distribution subsystems with AC power.

B.1

With one 120-Vac Class 1E bus subsystem inoperable, the remaining OPERABLE 120-Vac Class 1E buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC Class 1E bus subsystem must be powered from an alternate source within 2 hours by powering the bus from the associated inverter via inverted DC, inverter using internal AC source, or Class 1E

(continued)

ACTIONS

B.1 (continued)

constant voltage transformer. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The required AC Class 1E bus subsystems must then be re-powered by restoring it's associated inverter to OPERABLE status within 24 hours under LCO 3.8.7. ACTION A.1.

Condition B represents one 120-Vac Class 1E bus 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 Class 1E buses and restoring power to the affected 120-Vac Class 1E bus subsystem.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate 120-Vac power. Taking exception to LCO 3.0.2 for components without adequate Class 1E 120-Vac 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 Class 1E 120-Vac power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected subsystem; 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 120-Vac Class 1E bus to OPERABLE status, the redundant capability afforded by the other OPERABLE 120-Vac Class 1E buses, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

C.1

With one DC electrical power distribution subsystem inoperable, the remaining portions of the DC electrical power distribution subsystem 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 portion of the DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

Condition C represents one DC electrical power distribution subsystem without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning for the affected bus. 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 DC electrical power distribution subsystems and restoring power to the affected subsystem.

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;

(continued)

BASES

ACTIONS

C.1 (continued)

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 subsystem; 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 the applicable guidance discussed in Reference 3.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

(continued)

BASES

ACTIONS (continued)	E.1 Condition E corresponds to two required Class 1E AC, DC, or 120-Vac buses with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other PG&E Design Class I functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.
SURVEILLANCE REQUIREMENTS	SR 3.8.9.1 This Surveillance verifies that the required Class 1E AC, DC, and 120-Vac 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. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. Table B 3.8.9-1 The table on the next page defines the general features of the AC and DC Electrical Power Distribution System.
REFERENCES	1. UFSAR, Chapter 6 2. UFSAR, Chapter 15 3. NUREG-1151, "Technical Specifications Diablo Canyon Nuclear Power Plant, Units 1 and 2," August 1985. (TS Bases 3/4.8.1, 3/4.8.2, 3/4.8.3) 4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

LCO 3.8.9 CONDITION A
4.16-kV and 480-V

VOLTAGE	BUS F MAJOR ESF LOADS (TRAIN A)	BUS G MAJOR ESF LOADS (TRAIN B)	BUS H MAJOR ESF LOADS (TRAIN A&B)
4.16-kV	ASW PP 1 AFW PP 3 CC PP 1 CCW PP 1 SI PP 1 480-V BUS F	ASW PP 2 CS PP 1 RHR PP 1 CC PP 2 CCW PP 2 480-V BUS G	AFW PP 2 (B) CS PP 2 (A) RHR PP 2 (A) SI PP 2 (B) CCW PP 3 (A&B) 480-V BUS H
480-V *	CFCU 1 CFCU 2	CFCU 3 CFCU 5	CFCU 4 (A&B)

* Partial listing of loads

LCO 3.8.9 CONDITION B
120-Vac

BUS 1 PY11 (21)** PY11A (21A)**	BUS 2 PY12 (22)**	BUS 3 PY13 (23)** PY13A (23A)**	BUS 4 PY14 (24)**
IY Powered by: 480-V BUS F/DC BUS 1 or TRY1 Powered by: 480-V BUS F or Backup 480-V BUS G	IY1 Powered by: 480-V BUS G/DC BUS 2 or TRY2 Powered by: 480-V BUS G or Backup 480-V BUS F	IY Powered by: 480-V BUS H/DC BUS 3 or TRY3 Powered by: 480-V BUS H or Backup 480-V BUS G	IY Powered by: 480-V BUS H/DC BUS 2 or TRY4 Powered by: 480-V BUS H or Backup 480-V BUS F

** Unit 2 in parentheses

LCO 3.8.9 CONDITION C
125-Vdc

DC BUS 1 - Powered From:	DC BUS 2 - Powered From:	DC BUS 3 - Powered From:
Battery 1 and Battery Charger 11 (21)** or Battery Charger 121 (221)**	Battery 2 and Battery Charger 12 (22)** or Battery Charger 121 (221)**	Battery 3 and Battery Charger 131 (231)** or Battery Charger 132 (232)**

** Unit 2 in Parentheses

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

BACKGROUND	A description of the Class 1E AC, DC, and 120-Vac Class 1E 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 Class 1E AC, DC, and 120-Vac 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 Class 1E AC, DC, and 120-Vac 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 Class 1E AC, DC, and 120-Vac 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, AC and DC electrical power is only required to mitigate fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours). The Class 1E AC, DC, and 120-Vac 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 plant condition. An OPERABLE AC subsystem shall consist of a 4.16-kV Class 1E bus powered from at least one energized offsite power source with the capability of being powered from an OPERABLE DG. The DG may be the DG associated with that bus or, with administrative controls in place, a DG that can be cross-tied (via the startup cross-tie feeder breakers) to another bus. However, credit for this cross-tie capability

(continued)

BASES

LCO (continued)	cannot be taken credit for in those LCOs which specifically require an OPERABLE emergency power source. The latter ensures that the 4.16-kV bus will be immediately available after a LOOP without operator action. An OPERABLE DC subsystem consists of an OPERABLE DC bus (refer to B 3.8.5). An OPERABLE Class 1E 120-Vac subsystem consists of a Class 1E 120-Vac bus that is powered by its OPERABLE inverter which is connected to an OPERABLE DC bus per LCO 3.8.8, or one that is powered from its associated Class 1E 120-Vac regulating transformer that is selected to be powered from an OPERABLE AC Class 1E bus. This ensures that the Class 1E 120-Vac bus is capable of supplying either uninterruptable power from its associated inverter, or with administrative controls in place, from its Class 1E 120-Vac regulating transformer after a brief time delay for the DG to load the bus following a LOOP. The 120-Vac regulating transformer must be capable of being energized without any operator action. 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, DC, and 120-Vac 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 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 120-Vac Class 1E bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

(continued)

BASES (continued)

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 subsystems of electrical power distribution systems to be OPERABLE, one OPERABLE distribution subsystem 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 that 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, DC, and 120-Vac 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. 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.8.10.1 This Surveillance verifies that the Class 1E AC, DC, and 120-Vac 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. 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. License Amendment 184/186, January 3, 2006

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the filled portions of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity, that have direct access to the reactor vessel, 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. The refueling boron concentration is sufficient to maintain shutdown margin (SDM) with the most adverse conditions of fuel assembly and control rod position allowed by plant procedures. The boron concentration that is maintained in MODE 6 is sufficient to maintain $k_{eff} \leq 0.95$ with the most reactive rod control assembly completely removed from its fuel assembly.

GDC 26, 1971 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the principle 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 refueling grade borated water from the liquid hold up tanks or the refueling water storage tank.

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation during refueling (refer to 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 cooling in the RCS and assist in maintaining the boron concentration uniformity in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS	During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis 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 core mapping) ensure that the k_{eff} of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% Δk/k margin of safety is established during refueling. During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes. The limiting boron dilution accident analyzed occurs in MODE 5 (Ref. 2). It is based upon a maximum dilution flow of 200 g.p.m. and prompt identification and operation preclude the event from proceeding to a boron dilution accident. Prompt identification is assured through audible count rate instrumentation, visual count rate instrumentation and a high flux at shutdown alarm. The RCS boron concentration satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).
LCO	The LCO requires that a minimum boron concentration be maintained in the filled portions of the RCS, the refueling canal, and the refueling cavity that have direct access to the reactor vessel 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.

(continued)

BASES (continued)

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits," ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

This Specification has no LCO 3.0.4.c exception and LCO 3.0.4 places no restrictions on MODE changes that are part of the shutdown of the unit. However, since this Specification has Required Actions with immediate Completion Times, entering MODE 6 will not be permitted unless the boron concentration limits of this LCO are met. This will assure that the core reactivity is maintained within limits during fuel handling operations. The risk assessments of LCO 3.0.4.b may only be utilized for systems and components. However, since boron concentration does not demonstrate system/component operability and the Required Actions have immediate completion times, a risk assessment per LCO 3.0.4.b to allow MODE changes with single or multiple system/equipment inoperabilities may not be used to allow a MODE change into this LCO while not meeting the Mode 6 Boron Concentration limits, even if the risk assessment specifically includes consideration of the Mode 6 Boron Concentration.

(continued)

BASES (continued)

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, and when connected, 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, inventory addition, or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

A.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the filled portions of the RCS, the refueling canal, and the refueling cavity that have direct access to the reactor vessel is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical 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. 10 CFR 50, Appendix A, GDC 26, 1971
2. UFSAR, Section 15.2.4

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 (source range drawer) covers six decades of neutron flux (1 to 1E+6 cps) with a ± 3% instrument accuracy. The detectors also provide continuous visual indication in the control room and an audible alarm and count rate to alert operators to a possible dilution accident. The NIS is designed in accordance with the criteria presented in Reference 1. In addition to the other indicators, these detectors provide an audible count rate in the containment.

The Gamma-Metrics neutron flux monitors (N-51 and N-52) are designed in accordance with Regulatory Guide 1.97. The wide range neutron flux monitors in this system provide indication of neutron flux from reactor shutdown to reactor full power level (source range through power range). The wide range monitors (1E-8 to 1E+2 % power) provide continuous visual indication in the control room to allow operators to monitor core flux. The narrow range monitors (1E-1 to 1E+5 cps) provides indication of neutron flux to the hot shut down panel and control room by way of the plant process computer (PPC) and can be used in place of one of the permanently installed source range neutron flux monitors in Mode 6. The alternate Gamma-Metrics neutron flux monitor must be powered by a different OPERABLE Class 1E 120-Vac power supply than the other OPERABLE source range neutron flux monitor (Reference 5). If source range neutron flux monitor N32 is inoperable, Gamma-Metrics neutron flux monitor N51 CANNOT be used in place because both source range neutron flux monitor N31 and Gamma-Metrics neutron flux monitor N51 are powered from the same instrument inverter IY11. If source range neutron flux monitor N31 is inoperable, there is no restriction on which Gamma-Metrics neutron flux monitors can be used in place because they are all powered from different instrument inverters.

(continued)

BASES

BACKGROUND (continued)	The core off-load and re-load patterns must be analyzed to support the use of one of the Gamma-Metrics neutron flux monitors. Since the Gamma-Metrics neutron flux monitor provides indication of neutron flux to the control room by way of the PPC, the Gamma-Metrics neutron flux monitor cannot be considered an acceptable OPERABLE alternate source range flux monitor if the PPC cannot provide proper indication of neutron flux from the Gamma-Metrics monitor.
APPLICABLE SAFETY ANALYSIS	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) or an improperly loaded fuel assembly. Prompt identification is required to assure sufficient time for operator action to preclude the event from proceeding to a Boron Dilution Accident. Prompt identification is assured through audible count rate indication, a visual flux indication and a high source range flux level alarm in the control room. Although an audible count rate is provided in the containment it is not credited for OPERABILITY of the flux monitors. The source range neutron flux monitors satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

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. To be OPERABLE, each monitor must provide visual indication and at least one of the two monitors must provide an audible alarm and count rate indication in the Control Room. Therefore, with no audible alarm and count rate indication from at least one monitor, both monitors are inoperable until the audible indication is restored to the operable monitor – Action A must also be entered with no audible count rate indication in the control room.
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	<u>A.1 and A.2</u> 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 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. The exception given in A.1 for the process of latching/unlatching control rods and friction testing of control rods is provided to allow completion of head installation prior to replacing a failed source range detector. RCCA latching and friction testing is conducted with the reactor vessel upper internals in place, thereby preventing the lowering of a temporary source range detector into the region of the core. This NOTE allows control rod movement with only one source range in place. Friction testing involves fully withdrawing and reinserting each rod in turn, which could change core reactivity by as much as one percent for the most reactive rod. The increase in count rate would be one to two counts per second. For Gamma Metrics, the increase in count rate would be 0.1 to 0.2 counts per second.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The core coupling in this configuration would allow one source range detector to detect significant reactivity changes associated with control rod movement (Ref. 3). Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position or normal cooldown of a coolant volume for the purpose of system temperature control.

B.1

With no source range neutron flux monitor OPERABLE including no OPERABLE audible alarm and count rate functions, 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 including an OPERABLE audible alarm and count rate functions 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 boron concentration changes inconsistent with Required Action A.2 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.

The Completion Time of once per 12 hours 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. For core reload, the first CHANNEL CHECK for each channel may be performed using the first fuel assembly as a source, prior to unlatching it 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.9.3.2 SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the normal N31 and N32 source range neutron flux monitors is described in B 3.3.1, "Reactor Trip System (RTS) Instrumentation." The CHANNEL CALIBRATION for the normal N31 and N32 audible alarm and count rate functions includes verification of the control room audible alarm and count rate functions using a simulated signal. 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 A, GDC 13, 1971 (associated with 1967 GDCs 12, 13, 14, and 15 per UFSAR Appendix 3.1A); GDC 26, 1971; GDC 28, 1971; and GDC 29, 1971
2. UFSAR, Section 15.2.4
3. License Amendment 46/45, October 4, 1989
4. NRC letter, "Diablo Canyon Nuclear Power Plant, Unit Nos.1 and 2 – Technical Specification Bases Change (TAC Nos. M98430 and M98431)," June 9, 1998
5. PG&E DCL 97-035, March 18, 1997

B 3.9 REFUELING OPERATIONS

B 3.9.4 Containment Penetrations

BASES

BACKGROUND	In MODES 1, 2, 3, and 4, 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 10CFR50.67. Additionally, in all operating modes the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions. However during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to maintain the pressure boundary can be less stringent. An analysis has been performed that shows by meeting the LCO, during CORE ALTERATION and movement of irradiated fuel assemblies in containment, the potential release as a result of a fuel handling accident (FHA) will remain within the requirements of 10 CFR 50.67 limits.
	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. The LCO requires that during CORE ALTERATIONS or the movement of irradiated fuel assemblies the equipment hatch must be capable of being closed and 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 Personnel Air Lock (PAL) and Emergency Air Lock (EAL), which are also part of the containment pressure boundary, provide a means for personnel and emergency access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each of these air locks 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 the PAL and EAL are not required to be closed, the door interlock mechanisms may be disabled, allowing both doors of each of the air locks to remain open for extended periods when frequent containment entry is necessary.

(continued)

BASES

BACKGROUND (continued)

Per the FHA inside containment analysis, there are no closure restrictions required to limit any release to within the requirements of 10 CFR 50.67 limits for offsite dose as the result of a fuel handling accident during refueling. The LCO requirements for containment penetration closure are not provided to meet regulatory requirements, but rather to reduce the potential volume of the release of fission product radioactivity within containment to the environment.

The Containment Purge and Exhaust System includes two subsystems. The normal subsystem includes a 48 inch purge penetration and a 48 inch exhaust penetration. The second subsystem, a pressure equalization system provides a single 12 inch supply and exhaust penetration. Each of these systems are qualified to closed automatically by the Engineered Safety Features Actuation System (ESFAS).

In MODE 6, large air exchanges are necessary to conduct refueling operations. The normal 48 inch purge system is used for this purpose, and all four valves are closed by the ESFAS in accordance with LCO 3.3.6, "Containment Purge and Exhaust Isolation Instrumentation."

The pressure equalization system is disassembled and used in MODE 6 for other outage functions.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side if they are not opened under administrative controls. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. The fuel transfer tube is open but closure is provided by an equivalent isolation of a water loop seal. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, ventilation barrier for the other containment penetrations during fuel movements (Ref. 1).

Although the historic severe weather patterns for DCPP do not require consideration of tornados as part of the design basis, severe weather conditions might occur at the site that could necessitate closure of open penetrations with direct access to the outside atmosphere during refueling operations with core alterations or irradiated fuel movement inside containment. As a result, administrative procedures shall require that closure of these penetrations be initiated immediately if severe weather warnings are in effect. All fuel handling activities inside containment shall be suspended until closure of the equipment hatch is completed.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS	During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 2). Fuel handling accident inside the containment is based on dropping a single irradiated fuel assembly of which all 264 fuel rods rupture. In addition the analysis assumes free and rapid communication of air from the containment to the outside environment; the accident occurs 72 hours after reactor shutdown; almost instantaneous release of the entire containment volume to the outside atmosphere; a radial peaking factor of 1.65 based on 105% full power operation; and the other guidance from RG 1.183. (Ref 5).
	The requirements of LCO 3.9.7, "Refueling Cavity Water Level," and the minimum decay time of 100 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses less than the accident dose criteria specified in Table 6 of RG 1.183 (Ref. 5)
	Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

This LCO limits the consequences of a fuel handling accident 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 or capable of being closed. For the OPERABLE containment purge and exhaust penetrations, this LCO ensures that these penetrations are isolable by the Containment Purge and Exhaust Isolation System. The OPERABILITY requirements for this LCO ensure that the automatic purge and exhaust valve closure times specified in the UFSAR can be achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

This LCO allows the equipment hatch to be open during CORE ALTERATIONS or the movement of irradiated fuel assemblies in containment provided it is capable of being closed and the following administrative controls are established and maintained: 1) appropriate personnel are aware of the open status of the equipment hatch; 2) specific individuals are designated, trained and readily available to effect the closure of the equipment hatch; 3) the tools and equipment required to support the closure of the equipment hatch and the location of these tools and equipment relative to the equipment hatch are controlled; and 4) any potential obstruction (e.g., cables, hoses, etc.) that could prevent rapid closure of the equipment hatch can be quickly removed to support immediate initiation of closure and completion of closure within approximately 30 minutes.

The LCO allows both of the personnel air lock (PAL) doors and both of the emergency air lock (EAL) doors to be open during CORE ALTERATIONS or the movement of irradiated fuel assemblies, provided one of the PAL doors and one of the EAL doors is capable of being closed. This is acceptable if administrative controls are established and maintained to ensure that: 1) appropriate personnel are aware of the open status of the PAL and/or EAL doors; 2) specific individuals are designated, trained and readily available to effect the closure of the PAL and EAL doors; 3) the tools and equipment required to support the closure of the PAL and EAL doors and the location of these tools and equipment relative to the PAL and EAL doors are controlled; and 4) any potential obstruction (e.g., cables, hoses, etc.) that could prevent rapid closure of the PAL and EAL doors can be quickly removed to support immediate initiation of closure and completion of closure within approximately 30 minutes.

(continued)

BASES

LCO (continued)	The LCO is also 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. The required administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment; and 2) specific individuals are designated, trained and readily available to effect the closure of the penetrations; 3) the tools and equipment required to support the closure of the penetrations and the location of these tools and equipment relative to the penetrations are controlled; and 4) any potential obstruction (e.g., cables, hoses, etc.) that could prevent rapid closure of the penetrations can be quickly removed to support immediate initiation of closure and completion of closure within approximately 30 minutes.
APPLICABILITY	The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.
ACTIONS	A.1 and A.2 If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Containment Purge and Exhaust Isolation System not capable of automatic 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 CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates by inspection or administrative means that each of the containment penetrations is closed or capable of being closed. 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 closed by an OPERABLE automatic containment purge and exhaust isolation signal.

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

SR 3.9.4.2

This Surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES	1.	Design Criteria Memorandum T-16, Containment Functions.
	2.	UFSAR, Section 15.4.5 and 15.5.22.
	3.	Not Used.
	4.	Not Used.
	5.	RG 1.183, July 2000.
	6.	10 CFR 50.67.

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), as required by GDC 34, 1971 (DCPP meets the intent of this 1971 GDC), 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 lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.
APPLICABLE SAFETY ANALYSIS	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 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 de-energizing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional de-energizing of the RHR pump does not result in a challenge to the fission product barrier. Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in 10 CFR 50.36(c)(2)(ii) as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.
LCO	Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation to provide: a. Removal of decay heat;

(continued)

BASES

LCO (continued)

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 low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. Management of gas voids is important to RHR System OPERABILITY.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations 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 minimum required RCS boron concentration is maintained is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as valve testing, core mapping, or alterations in the vicinity of the reactor vessel hot leg nozzles. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

The LCO is also modified by a second Note that allows the required RHR Loop to be removed from service for up to 2 hours per 8 hour period to support surveillance leak rate testing of the RCS to RHR suction isolation valves, provided that no operations are permitted which might result in reduction of boron concentration. During this 2 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity and the RCS.

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), and Section 3.5, Emergency Core Cooling Systems (ECCS). 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."

(continued)

BASES (continued)

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Notes to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that 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 an irradiated 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

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.5.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate of 3000 gpm is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core prior to 57 hours of core subcriticality. The second part of this Surveillance serves the same function but with 57 hours or more of core subcriticality. The flow rate of 1300 gpm is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. Both of these flow rates are points of the same flow rate verses 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 3.9.5.2

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.
REFERENCES	1. UFSAR, Section 5.5.7 2. License Amendment 28/27, January 5, 1988 3. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, “Generic Letter 2008-01, Managing Gas Accumulation,” Using the Consolidated Line Item Improvement Process.

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), as required by GDC 34, 1971 (DCPP meets intent of this 1971 GDC), 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 ANALYSIS	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 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, to prevent this challenge. Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in 10CFR50.36(c)(2)(ii) as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.
LCO	In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE. Additionally, one loop of RHR must be in operation in order to provide: a. Removal of decay heat; b. Mixing of borated coolant to minimize the possibility of criticality; and c. Indication of reactor coolant temperature.

(continued)

BASES

LCO (continued)	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 low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. Management of gas voids is important to RHR System OPERABILITY. An operable RHR loop must be capable of being realigned to provide an operable flow path.
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), and Section 3.5, Emergency Core Cooling Systems (ECCS). 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 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. 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 required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

(continued)

BASES

ACTIONS (continued)

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable at water levels above reduced inventory, based on the low probability of the coolant boiling in that time. At reduced inventory conditions or mid-loop operations, additional actions are taken to provide containment closure in a reduced period of time (Ref. 3). Reduced inventory is defined as less than Elev. 111 ft.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate of more than 3000 gpm is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core prior to 57 hours subcritical. The second part of this Surveillance serves the same function but with 57 hours or more of core subcriticality and provides a reduced flow rate of 1300 gpm based upon a reduced decay heat load. Both of these flow rates are points of the same flow rate verses decay heat curves. The 1300 gpm limit also precludes exceeding the 1675 gpm upper flow limit to prevent vortexing and air entrainment of the RHR piping system. RHR pump vortexing (failure to meet pump suction requirements) during mid-loop operation may result in RHR pump failure and non-conservative RCS level indication. 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 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.6.3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	SR 3.9.6.3 (continued) OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES	1. UFSAR, Section 5.5.7 2. License Amendment 28/27, January 5, 1988 3. Generic Letter 88-17, “Loss of Decay Heat Removal” 4. Amendments 228/230; LAR 16-01 Application to Revise Technical Specifications to Adopt TSTF-523, “Generic Letter 2008-01, Managing Gas Accumulation,” Using the Consolidated Line Item Improvement Process.

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 acceptance criteria of 10 CFR 50.67 (Ref. 4) and RG 1.183 (Ref. 1).
APPLICABLE SAFETY ANALYSIS	During CORE ALTERATIONS and 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 a decontamination factor of 200 (Appendix B (2) of Ref. 1 approved in Ref. 7) 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 I-131, 23% of I-132 and 5% of core inventory of all other iodine isotopes (Ref. 2). The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 100 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Refs. 1 and 4). Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as provided by the guidance of Reference 1.

(continued)

BASES (continued)

APPLICABILITY	LCO 3.9.7 is applicable during CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, and 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 3.7.15, "Fuel Storage Pool Water Level."
ACTIONS	<u>A.1</u> 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	<u>SR 3.9.7.1</u> 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 15.4.5 and 15.5.22. 3. Not Used. 4. 10 CFR 50.67. 5. Not Used. 6. Not Used. 7. License Amendment 155/155, October 21, 2002