Consumers Energy

A CMS Energy Company

Palisades Nuclear Plant
27780 Blue Star Memorial Highway
Covert, MI 49043

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U.S. Nuclear Regulatory Commission
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DOCKET 50-255 - LICENSE DPR-20 - PALISADES PLANT CONVERSION TO IMPROVED TECHNICAL SPECIFICATIONS; CLEAN COPIES OF IMPROVED TECHNICAL SPECIFICATIONS AND BASES

On January 26, 1998, Consumers Energy Company submitted a Technical Specification Change Request (TSCR) to convert the Palisades Technical Specifications to closely emulate the Standard Technical Specifications for Combustion Engineering Plants, NUREG-1432. During their review of that submittal, the NRC staff provided several comments on these proposed Technical Specifications and the associated bases. The January 26, 1998 submittal was supplemented in response to those comments in letters dated:

April 30, 1998,	Implementation Date	
September 14, 1998	RAI Responses Sections	3.8 & 5.0
October 12, 1998	RAI Responses Sections	1.0, 3.0, 4.0, & 5.0
November 9 1998	RAI Responses Sections	3.4 & 3.9
March 1, 1999	RAI Responses Sections	2.0, 3.1, 3.2, & 5.0
March 22, 1999	Changes to ITS Section	3.4
March 30, 1999	RAI Responses Section	3.7
April 7, 1999	Changes to ITS Section	3.1
May 3, 1999	RAI Responses Sections	3.5 & 3.8
June 4, 1999	RAI Responses Section	3.6 - Partial
June 11, 1999	RAI Responses Sections	1.0, 3.3, 3.4, & 3.9
June 17, 1999	RAI Responses Section	3.6 - Remainder
July 19, 1999	Changes to ITS Section	3.7
July 30, 1999	Changes to ITS Sections	3.3, 3.5, 3.6, & Editorials

This letter provides final clean copies of those Improved Technical Specifications (ITS) and Bases which incorporate all changes proposed in the above listed letters. These clean copies also incorporate some editorial changes and Bases clarifications as a result of ongoing reviews to ITS LCOs 3.5.2, 3.6.3, 3.6.6, 3.7.5, 3.7.7 and 3.7.8 by both Consumers Energy and the NRC staff.

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The following Enclosures to this letter have been provided:

Enclosure 1 contains a complete set of ITS pages incorporating the ITS submitted in our January 26, 1998 letter and all of the changes provided in the above listed letters, and editorial changes for the description of Condition A in LCOs 3.5.2, 3.6.6, 3.7.5, 3.7.7 and 3.7.8 which have been discussed with the NRC staff.

Enclosure 2 contains a complete set of ITS Bases pages incorporating the ITS Bases submitted in our January 26, 1998 letter, all of the changes provided in the above listed letters, and additional Bases clarifications for Sections 3.5.2, 3.6.3, 3.6.6, 3.7.5, 3.7.7 and 3.7.8 which have been discussed with the NRC staff.

SUMMARY OF COMMITMENTS

This submittal contains no new commitments and no revisions to existing commitments.

David W. Rogers
General Manager, Operations

CC Administrator, Region III, USNRC
Project Manager, NRR, USNRC
NRC Resident Inspector - Palisades

Enclosures

CONSUMERS ENERGY COMPANY
CLEAN COPIES OF IMPROVED TECHNICAL SPECIFICATIONS AND BASES

To the best of my knowledge, the content of this submittal of clean Improved Technical Specifications (ITS) pages including the ITS submitted in our January 26, 1998 License Amendment request and all of the changes provided in response to the NRC comments, is truthful and complete.

David W. Rogers
General Manager, Operations

Sworn and subscribed to before me this 17th day of September 1999.

Mary Ann Engle
Mary Ann Engle, Notary Public
Berrien County, Michigan
(Acting in Van Buren County, Michigan)
My commission expires February 16, 2000

50-255 CEC PALISADES

CONVERSION TO IMPROVED TECH SPECS,
IMPROVED TECH SPECS BASES, CLEAN
PAGES Enclosure 2

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ENCLOSURE 2

CONSUMERS ENERGY COMPANY
PALISADES PLANT
DOCKET 50-255

CONVERSION TO IMPROVED
TECHNICAL SPECIFICATIONS

IMPROVED TECHNICAL SPECIFICATIONS BASES
CLEAN PAGES

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

The Palisades Nuclear Plant design criteria (Ref. 1) requires, and these SLs ensure, 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 (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 and possible cladding perforation that would result in the release of fission products to the primary 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 primary coolant.

Operation above the boundary of the nucleate boiling regime beyond onset of DNB could result in excessive cladding temperature because of the resultant sharp reduction in the heat transfer coefficient in the transition and film boiling regimes. If a steam film is allowed to form, 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 primary coolant.

BASES

BACKGROUND (continued)

The Reactor Protective System (RPS), in combination with the LCOs, is designed to prevent any anticipated combination of transient conditions for Primary Coolant System (PCS) temperature, pressure, and THERMAL POWER level that would result in a violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

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

a. There must be at least a 95% probability at a 95% confidence level (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.

Palisades uses three DNB correlations; the XNB, ANFP, and HTP detailed in References 3 through 8. The DNB correlations are used solely as analytical tools to ensure that plant conditions will not degrade to the point where DNB could be challenged. The XNB correlation is used for non-High Thermal Performance (HTP) assemblies (assemblies loaded prior to cycle 9), when the non-HTP assemblies could have been limiting. The non-HTP fuel assemblies are used for vessel fluence reduction and reside on the core periphery. The core periphery locations operate at relatively low relative power fractions; therefore, they are not DNB limiting assemblies. The XNB correlation provides administrative justification for using non-HTP assemblies in Palisades low leakage core design. The ANFP and HTP correlations are used for Palisades High Thermal Performance (HTP) fuel assemblies (assemblies loaded in cycle 9 and later).

The HTP correlation can be used when the calculated reactor coolant conditions fall within the correlation's applicable coolant condition ranges. Outside of the applicable range of the HTP correlation, the ANFP correlation can be used. The ANFP correlation may be used over a broader range of coolant conditions than the HTP correlation. The HTP correlation is an extension of the ANFP correlation and incorporates the results of test sections designed to represent HTP fuel design for CE plants.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The prediction of DNB is a function of several measured parameters. The following trip functions and LCOs, limit these measured parameters to protect the Palisades reactor from approaching conditions that could lead to DNB:

Parameter	Protection
Core Flow Rate	Low PCS Flow Trip
Core Power	Variable High Power Trip
PCS Pressure/Core Power	TM/LP Trip
Core Inlet Temperature T_{inlet} LCO	
Axial Shape Index (ASI)	ASI LCO
Assembly Power	Incore Power Monitoring (LHR and Radial Peaking Factor LCOs)

The RPS setpoints, LCO 3.3.1, "Reactor Protective System (RPS) Instrumentation," in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for PCS 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.

The SL represents a design requirement for establishing the protection system trip setpoints identified previously. LCO 3.2.1, "Linear Heat Rate (LHR)," and LCO 3.2.2, "Radial Peaking Factors," or the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

SL 2.1.1.1 and SL 2.1.1.2 ensure that the minimum DNBR is not less than the safety analyses limit and that fuel centerline temperature remains below melting.

The minimum value of the DNBR during normal operation and design basis AOOs is limited to the following DNB correlation safety limit:

Correlation	Safety Limit
XNB	1.17
ANFP	1.154
HTP	1.141

The fuel centerline melt LHR value assumed in the safety analysis is 21 kw/ft. Operation $\leq$ 21 kw/ft maintains the dynamically adjusted peak LHR and ensures that fuel centerline melt will not occur during normal operating conditions or design AOOs.

BASES

APPLICABILITY

SL 2.1.1.1 and SL 2.1.1.2 only apply 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 are available to prevent PCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the plant into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1.

In MODES 3, 4, 5, and 6, a reactor core SL is not required, since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

The following violation responses are applicable to the reactor core SLs.

2.2.1

If SL 2.1.1.1 or SL 2.1.1.2 is violated, the requirement to go to MODE 3 places the plant in a MODE in which this SL is not applicable.

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

REFERENCES

1. FSAR, Section 5.1
2. FSAR, Chapter 14
3. XN-NF-621(A), Rev 1
4. XN-NF-709
5. ANF-1224(A), May 1989
6. ANF-89-192, January 1990
7. XN-NF-82-21, Rev 1
8. EMF-92-153(A) and Supplement 1, March 1994

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Primary Coolant System (PCS) Pressure SL

BASES

BACKGROUND

The SL on PCS pressure protects the integrity of the PCS against overpressurization. In the event of fuel cladding failure, fission products are released into the primary coolant. The PCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on PCS pressure, continued PCS integrity is ensured. According to Palisades Nuclear Plant design criteria (Ref. 1), the Primary Coolant Pressure Boundary (PCPB) design conditions are not to be exceeded during normal operation and Anticipated Operational Occurrences (AOOs). Also, according to Palisades Nuclear Plant design criteria (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the PCPB greater than limited local yielding.

The design pressure of the PCS is 2500 psia. During normal operation and AOOs, the PCS pressure is kept from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2) and by the piping, valve, and fitting limit of 120% of design pressure (Ref. 6). The initial hydrostatic test was conducted at 125% of design pressure (3125 psia) to verify the integrity of the primary coolant system (Ref. 2). Following inception of plant operation PCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the PCS could result in a breach of the PCPB. If this 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 100, "Reactor Site Criteria" (Ref. 4).

BASES

APPLICABLE SAFETY ANALYSES

The PCS primary safety valves, the Main Steam Safety Valves (MSSVs), and the High Pressurizer Pressure trip have settings established to ensure that the PCS pressure SL will not be exceeded.

The PCS primary safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence the valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings, and nominal feedwater supply is maintained.

The Reactor Protective System (RPS) trip setpoints (LCO 3.3.1, "Reactor Protective System (RPS) Instrumentation"), together with the settings of the MSSVs (LCO 3.7.1, "Main Steam Safety Valves (MSSVs)") and the primary safety valves, provide pressure protection for normal operation and AOOs. In particular, the High Pressurizer Pressure Trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). Conservative values for all system parameters, delay times and core moderator coefficient are assumed.

More specifically, for the limiting case, no credit is taken for operation of any other pressure relieving system including the following:

a. Pressurizer Power Operated Relief Valves (PORVs);

b. Turbine Bypass Control System;

c. Atmospheric Steam Dump Valves;

d. Pressurizer Level Control System; or

e. Pressurizer Pressure Control System.

SAFETY LIMITS

The maximum transient pressure allowable in the PCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the PCS piping, valves, and fittings under 120% of design pressure (Ref. 6). The most limiting of these two allowances is the 110% of design pressure; therefore, the SL on maximum allowable PCS pressure is established at 2750 psia.

BASES

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, 5, and 6 because this SL could be approached or exceeded in these MODES due to overpressurization events. In MODE 6 with the reactor vessel head installed and the reactor vessel head closure bolts less than fully tensioned the potential for an over pressurization event still exists. Although overpressurization of the PCS is impossible once the reactor vessel head is removed, the requirements of this SL apply as long as fuel is in the reactor. Once all the fuel has been removed from the reactor, the requirements of SL 2.1.2 no longer apply.

SAFETY LIMIT VIOLATIONS

The following SL violation responses are applicable to the PCS pressure SLs.

2.2.2.1

If the PCS 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.

With PCS pressure greater than the value specified in SL 2.1.2 in MODE 1 or 2, the pressure must be reduced to below this value. A pressure greater than the value specified in SL 2.1.2 exceeds 110% of the PCS design pressure and may challenge system integrity.

The allowed Completion Time of 1 hour provides the operator time to complete the necessary actions to reduce PCS pressure by terminating the cause of the pressure increase, removing mass or energy from the PCS, or a combination of these actions, and to establish MODE 3 conditions.

2.2.2.2

If the PCS pressure SL is exceeded in MODE 3, 4, 5 or 6, PCS pressure must be restored to within the SL value within 5 minutes.

Exceeding the PCS pressure SL in MODE 3, 4, 5 or 6 is potentially 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. This 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.

BASES

REFERENCES

1. FSAR, Section 5.1

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

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

4. 10 CFR 100

5. FSAR, Section 4.3

6. ASA B31.1-1955, Code for Pressure Piping, 1967

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCO	LCO 3.0.1 through LCO 3.0.7 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 plant is in the MODES or other specified conditions of the Applicability statement of each Specification).
LCO 3.0.2	LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that: a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified. There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the plant in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.)

BASES

LCO 3.0.2 (continued)

The second type of Required Action specifies the remedial measures that permit continued operation of the plant that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

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

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "PCS 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 plant may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable and the ACTIONS Condition(s) are entered.

BASES

LCO 3.0.3

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

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

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

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

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the plant, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Primary 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.

BASES

LCO 3.0.3 (continued)

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

a. The LCO is now met.

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

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

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in MODE 5 when a shutdown is required during MODE 1 operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 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 29 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 31 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the plant is already in the most restrictive Condition required by LCO 3.0.3.

The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 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 plant shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the plant. An example of this is in LCO 3.7.14, "Spent Fuel Pool Water Level."

BASES

LCO 3.0.3 (continued)

LCO 3.7.14 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.14 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the plant in a shutdown condition. The Required Action of LCO 3.7.14 of "Suspend movement of irradiated fuel assemblies in spent fuel pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

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

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

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

Compliance with Required Actions that permit continued operation of the plant for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the plant before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions. 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.

BASES

LCO 3.0.4 (continued)

Exceptions to LCO 3.0.4 are stated in the individual Specifications. The exceptions allow 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. Exceptions may apply to all the ACTIONS or to a specific Required Action of a 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, changing MODES or other specified conditions while in an ACTIONS Condition, in compliance with LCO 3.0.4 or where an exception to LCO 3.0.4 is stated, is not a violation of SR 3.0.1 or SR 3.0.4 for those Surveillances that do not have to be performed due to the associated inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

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

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

b. The OPERABILITY of other equipment.

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.

BASES

LCO 3.0.5 (continued)

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

LCO 3.0.6

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

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

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

BASES

LCO 3.0.6 (continued)

Specification 5.5.13, "Safety Functions 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

Special tests and operations are required at various times over the plant's life to demonstrate performance characteristics, to perform maintenance activities, and to perform special evaluations. Because TS normally preclude these tests and operations, Special Test Exceptions (STEs) allow specified requirements to be changed or suspended under controlled conditions. STEs are included in applicable sections of the Specifications. Unless otherwise specified, all other TS requirements remain unchanged and in effect as applicable. This will ensure that all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed or suspended to perform the special test or operation will remain in effect.

The Applicability of an STE LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with STE LCO is optional.

A special test may be performed under either the provisions of the appropriate STE LCO or the other applicable TS requirements. If it is desired to perform the special test under the provisions of the STE LCO, the requirements of the STE LCO shall be followed. This includes the SRs specified in the STE LCO.

BASES

LCO 3.0.7 (continued)

Some of the STE LCO require that one or more of the LCO for normal operation be met (i.e., meeting the STE LCO requires meeting the specified normal LCO). The Applicability, ACTIONS, and SRs of the specified normal LCO, however, are not required to be met in order to meet the STE LCO when it is in effect. This means that, upon failure to meet a specified normal LCO, the associated ACTIONS of the STE LCO apply, in lieu of the ACTIONS of the normal LCO. Exceptions to the above do exist.

There are instances when the Applicability of the specified normal LCO must be met, where its ACTIONS must be taken, where certain of its Surveillances must be performed, or where all of these requirements must be met concurrently with the requirements of the STE LCO.

Unless the SRs of the specified normal LCO are suspended or changed by the special test, those SRs that are necessary to meet the specified normal LCO must be met prior to performing the special test. During the conduct of the special test, those Surveillances need not be performed unless specified by the ACTIONS or SRs of the STE LCO.

ACTIONS for STE LCO provide appropriate remedial measures upon failure to meet the STE LCO. Upon failure to meet these ACTIONS, suspend the performance of the special test and enter the ACTIONS for all LCOs that are then not met. Entry into LCO 3.0.3 may possibly be required, but this determination should not be made by considering only the failure to meet the ACTIONS of the STE LCO.

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 to be not met between required Surveillance performances.

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

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

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

BASES

SR 3.0.1 (continued)

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

An example of this process is:

a. High Pressure Safety Injection (HPSI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPSI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

SR 3.0.2

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

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

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. An example of where SR 3.0.2 does not apply is the Containment Leak Rate Testing Program.

BASES

SR 3.0.2 (continued)

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

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

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is less, 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 an 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 plant conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified plant conditions or operational situations, is discovered not to have been performed when specified, SR 3.0.3 allows the full delay period of 24 hours to perform the Surveillance.

BASES

SR 3.0.3 (continued)

SR 3.0.3 also provides a time limit for completion of Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

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

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

SR 3.0.4

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

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

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

BASES

SR 3.0.4 (continued)

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

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS.

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

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

The reactivity control systems must be redundant and capable of maintaining the reactor core subcritical when shut down under cold conditions, in accordance with the Palisades Nuclear Plant design criteria (Ref. 1). 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 events and Anticipated Operational Occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion of all full-length control rods, assuming that the single control rod of highest reactivity worth remains fully withdrawn. Once all full-length control rods have been verified to be at or below the lower electrical limit, the penalty for the control rod of highest reactivity worth fully withdrawn no longer must be applied.

The Palisades Nuclear Plant design criteria requires that two separate 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 rods and soluble boric acid in the Primary Coolant System (PCS). The Rod Control System provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel design limits, assuming that the control rod of highest reactivity worth remains fully withdrawn.

The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes, and maintain the reactor subcritical under cold conditions.

During MODES 1 and 2, SDM control is ensured by operating with the shutdown rods within the limits of LCO 3.1.5, "Shutdown and Part-Length Rod Group Insertion Limits," and the regulating rods within the limits of LCO 3.1.6, "Regulating Rod Group Position Limits." When the plant is in MODES 3, 4, 5, and 6 the SDM requirements are met by means of adjustments to the PCS boron concentration.

BASES

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analysis. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption that the control rod of highest reactivity worth is fully withdrawn following a reactor trip. For MODE 5, the primary safety analysis that 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 maintained. This is done by ensuring that:

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

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (Departure from Nucleate Boiling Ratio (DNBR), fuel centerline temperature limit AOOs, and ≤ 280 cal/gm energy deposition for the control rod ejection accident); and

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

The most limiting accident for the SDM requirements are based on a Main Steam Line Break (MSLB), as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected Steam Generator (SG), and consequently the PCS. This results in a reduction of the primary coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. The most limiting MSLB with respect to potential fuel damage is a guillotine break of a main steam line initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating PCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In addition to the limiting MSLB transient, the SDM requirement for MODES 3 and 4 must also protect against an inadvertent boron dilution; (Ref. 3) and an uncontrolled control rod bank withdrawal from subcritical conditions (Ref. 5).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the PCS 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.

The withdrawal of a control rod bank from subcritical conditions 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 withdrawal of control rod banks also produce a time dependent redistribution of core power.

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

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

LCO

The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the most limiting analyses that establish the value for SDM. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). For the boron dilution accident, if the LCO is violated, then the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

SDM is a core physics design condition that can be ensured through full-length control rod positioning (regulating and shutdown rods) and through the soluble boron concentration.

APPLICABILITY

In MODE 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 MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, and LCO 3.1.6. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration."

BASES

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 PCS as soon as possible, the boron injection flow should be a highly concentrated solution, such as that normally found in the concentrated boric acid storage tank. The operator should borate with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the PCS boron concentration is at the beginning of cycle, when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% $\Delta\rho$ must be recovered and a boration flow rate of 35 gpm, it is possible to increase the boron concentration of the PCS by 100 ppm in approximately 25 minutes. If a boron worth of 1.0 E-4 $\Delta\rho$/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta\rho$. These boration parameters of 35 gpm and 100 ppm represent typical values and are provided for the purpose of offering a specific example.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

SDM is verified by a reactivity balance calculation, considering the listed reactivity effects:

a. PCS boron concentration;

b. Control rod positions;

c. PCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration; and

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

f. Isothermal Temperature Coefficient (ITC).

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

Samarium is not considered in the reactivity analysis since the analysis assumes that the negative reactivity due to Samarium is offset by the positive reactivity of Plutonium built in.

SR 3.1.1.1 requires SDM to be within the limits specified in the COLR. This SDM value ensures the consequences of an MSLB, will be acceptable as a result of a cooldown of the PCS which adds positive reactivity in the presence of a negative moderator temperature coefficient as well as the other events described in the Applicable Safety Analysis. As such, the requirements of this SR must be met whenever the plant is in MODES 3, 4, and 5.

The Frequency of 24 hours for the verification of SDM is based on the generally slow change in required boron concentration, and also allows sufficient time for the operator to collect the required data, which may include performing a boron concentration analysis, and completing the calculation.

REFERENCES

1. FSAR, Section 5.1
2. FSAR, Section 14.14
3. FSAR, Section 14.3
4. 10 CFR 100
5. FSAR, Section 14.2

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Balance

BASES

BACKGROUND

According to the Palisades Nuclear Plant design criteria (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 SHUTDOWN MARGIN (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, 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. Excess reactivity can be inferred from the critical boron curve, which provides an indication of the soluble boron concentration in the Primary Coolant System (PCS) versus cycle burnup. Periodic measurement of the PCS boron concentration for comparison with the predicted value with other variables fixed (such as control 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.

BASES

BACKGROUND (continued)

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

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

APPLICABLE 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 control rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

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

BASES

APPLICABLE SAFETY ANALYSES (continued)

The comparison between measured and predicted initial core reactivity provides a normalization for calculational models used to predict core reactivity. If the measured and predicted PCS boron concentrations for identical core conditions at Beginning Of Cycle (BOC) are not within design tolerances, 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 critical boron curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

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

The reactivity balance satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

The reactivity balance limit is established to ensure plant operation is maintained within the assumptions of the safety analyses. 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% $\Delta\rho$ 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.

BASES

LCO (continued)

When measured core reactivity is within ± 1% Δρ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limits are normally detected by comparing predicted and measured steady state PCS 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 PCS boron concentration is 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 MODE 2 because enough operating margin exists to limit the effects of a reactivity anomaly, and THERMAL POWER is low enough (≤ 5% RTP) such that reactivity anomalies are unlikely to occur. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, or control rod replacement, or shuffling).

ACTIONS

A.1 and A.2

Should an imbalance 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.

BASES

ACTIONS

A.1 and A.2 (continued)

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 imbalance may be resolved. If the cause of the reactivity imbalance is a mismatch in core conditions at the time of PCS boron concentration sampling, then a recalculation of the PCS 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 imbalance 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 critical boron curve 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.

B.1

If the Required Actions for Condition A are not met within 7 days, 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. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted PCS 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, and xenon 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 in the Surveillance column which indicates that if the normalization of predicted core reactivity to the measured value is to occur, it must take place within the first 60 Effective Full Power Days (EFPD) after each refueling. 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 required subsequent Frequency of 31 EFPD following the initial 60 EFPD after entering MODE 1, is acceptable, based on the slow rate of core changes due to fuel depletion and the presence of other indicators (e.g., T_q, etc.) for prompt indication of an imbalance. A second Note, "only required after initial 60 EFPD," is added to the Frequency column to allow this.

REFERENCES

1. FSAR, Section 5.1

2. FSAR, Chapter 14

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to Palisades Nuclear Plant design criteria (Ref. 1), the reactor core and its interaction with the Primary Coolant System (PCS) 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 or rapid reactivity increases.

The MTC relates a change in core reactivity to a change in primary 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. 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 the measurement performed as part of startup testing following a refueling. Both initial and reload cores are designed so that the Beginning Of Cycle (BOC) MTC is less positive than that allowed by the LCO. The actual value of the MTC is dependent on core characteristics, such as fuel loading and primary coolant soluble boron concentration. The core design may require additional fixed distributed poisons (lumped burnable poison assemblies) 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. However, the safety analysis assumptions for the MTC at EOC are assumed by confirming the BOC MTC measurement is within limits which indicates the core is behaving as predicted.

BASES

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 during accidents, such as overheating and overcooling events.

Reference 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, such as very large soluble boron concentrations, to ensure the accident results are bounding (Ref. 3).

Accidents that cause core overheating, either by decreased heat removal or increased power production, must be evaluated for results when the MTC is positive. Examples of reactivity accidents that cause increased power production include the control rod bank withdrawal transient from either partial or RATED THERMAL POWER. The limiting overheating event relative to plant response is based on the maximum difference between core power and steam generator heat removal during a transient. Several events discussed in Reference 2 are analyzed with a positive MTC.

Accidents that cause core overcooling must be evaluated for results when the MTC is most negative. The event that produces the most rapid cooldown of the PCS, and is therefore the most limiting event with respect to the negative MTC, is a Main Steam Line Break (MSLB) event. Following the reactor trip for the postulated EOC MSLB event, the large moderator temperature reduction combined with the large negative MTC may produce reactivity increases that are as much as the shutdown reactivity. When this occurs, a substantial fraction of core power (approximately 12% RTP) is produced.

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

BASES

LCO

LCO 3.1.3 requires the MTC to be < 0.5 E-4 $\Delta\rho/°F$ at $\leq$ 2% RTP to ensure 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. The limit on a positive MTC ensures that core overheating accidents will not violate the accident analysis assumptions.

MTC is a core physics parameter determined by the fuel and fuel cycle design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement. The surveillance check at BOC on the MTC provide confirmation that the MTC is behaving as anticipated, so that the acceptance criteria are met.

APPLICABILITY

In MODE 1, the 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, the limits must also be maintained to ensure startup and subcritical accidents, such as the uncontrolled full-length control rod or group withdrawal, will not violate the assumptions of the accident analysis. The measurement of MTC in MODE 2 prior to exceeding 2% RTP is used to confirm that the core is behaving as analyzed. This ensures that the MTC will remain within the analyzed range while operating in MODES 1 and 2. In MODES 3, 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents (DBAs) using the MTC as an analysis assumption are initiated from these MODES. However, the variation of the MTC, with temperature in MODES 3, 4, and 5, for DBAs initiated in MODES 1 and 2, is accounted for in the subject accident analysis. The variation of the MTC, with temperature assumed in the safety analysis, is accepted as valid once the BOC measurement is used for normalization.

BASES

ACTIONS

A.1

MTC is a function of the fuel and fuel cycle designs, and cannot be controlled directly once the designs have been implemented in the core. If MTC exceeds its limits, the reactor must be placed in MODE 3. This eliminates the potential for violation of the accident analysis bounds. The associated Completion Time of 6 hours is reasonable, considering the probability of an accident occurring during the time period that would require an MTC value within the LCO limits, and the time for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The SR for measurement of the MTC at the beginning of each fuel cycle provides for confirmation of the limiting MTC values. The MTC changes smoothly from most positive (or least negative) to most negative value during fuel cycle operation as the PCS boron concentration is reduced to compensate for fuel depletion. The requirement for measurement prior to operation > 2% RTP satisfies the confirmatory check on the most positive (or least negative) MTC value. It also confirms that the core is behaving as analyzed which ensures that the MTC will remain within the analysis limits for the remainder of the fuel cycle.

REFERENCES

1. FSAR, Section 5.1
2. FSAR, Chapter 14
3. FSAR, Section 3.3

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Control Rod Alignment

BASES

BACKGROUND

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

The Palisades Nuclear Plant design criteria contain the applicable criteria for these reactivity and power distribution design requirements (Ref. 1).

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

Limits on control rod alignment and OPERABILITY have been established, and all control 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.

Control rods are moved by their Control Rod Drive Mechanisms (CRDMs). Each CRDM moves its rod at a fixed rate of approximately 46 inches per minute. Although the ability to move a full-length control rod by its drive mechanism is not an initial assumption used in the safety analyses, it is required to support OPERABILITY. As such, the inability to move a full-length control rod results in that full-length control rod being inoperable.

The control rods are arranged into groups that are radially symmetric. Therefore, movement of the control rod groups does not introduce radial asymmetries in the core power distribution. The shutdown and regulating rods provide the required reactivity worth for immediate reactor shutdown upon a reactor trip. The regulating rods also provide reactivity (power level) control during normal operation and transients.

BASES

BACKGROUND (continued)

The axial position of shutdown and regulating rods is indicated by two separate and independent systems, which are 1) synchro based position indication system, and 2) the reed switch based position indication system.

The synchro based position indication system measures the phase angle of a synchro geared to the CRDM rack. Full control rod travel corresponds to less than 1 turn of the synchro. Each control rod has its own synchro. The Primary Information Processor (PIP) node scans and converts synchro outputs into inches of control rod withdrawal. The resolution of this system is approximately 0.5 inches. Each synchro also has cam operated limit switches which can provide positive indication of control rod position.

The reed switch based position indication system is referred to as the Secondary Position Indication (SPI) system. This system provides a highly accurate indication of actual control rod position, but at a lower precision than the synchros. The reed switches are wired so that the voltage read across the reed switch stack is proportional to rod position. The reed switches are spaced along a tube with a center to center spacing distance of 1.5 inches. The resolution of the SPI reed switch stacks is 1.5 inches. The reed switches also provide input to the matrix indication lights which provide control rod status indication for various key positions. To increase the reliability of the system, there are redundant reed switches which prevent false indication in the event an individual reed switch fails.

A control rod position deviation alarm is provided to alert the operator when any two control rods in the same group are more than 8 inches apart. This helps to ensure any control rod misalignments are minimized. The alarm can be generated by either the SPI system or PIP node since the SPI system, in conjunction with the host computer, is redundant to the PIP node in the task of control rod measurements, control rod monitoring, and limit processing.

BASES

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Refs. 3 and 4). The accident analysis defines control rod misoperation as any event, with the exception of sequential group withdrawals, which could result from a single malfunction in the reactivity control systems. For example, control rod misalignment may be caused by a malfunction of the Rod Control System, or by operator error. A stuck rod may be caused by mechanical jamming. Inadvertent withdrawal of a single control rod may be caused by an electrical or mechanical failure in the Rod Control System. A dropped control rod could be caused by an electrical or mechanical failure in the CRDM.

The acceptance criteria for addressing control rod inoperability/misalignment are that:

a. There shall be no violations of:

   1. Specified Acceptable Fuel Design Limits (SAFDL), or

   2. Primary Coolant System (PCS) pressure boundary integrity; and

b. The core must remain subcritical after accident transients.

Three types of misoperations are discussed in the safety analysis (Ref. 4). During movement of a group, one control rod may stop moving while the other control rods in the group continue. This condition may cause excessive power peaking. The second type of misoperations occurs if one control 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 remaining control rods to meet the SDM requirement with the maximum worth rod stuck fully withdrawn. If a control rod is stuck in the fully withdrawn position, its worth is added to the SDM requirement, since the safety analysis does not take two stuck rods into account. The third type of misoperations occurs when one rod drops partially or fully into the reactor core. This event causes an initial power reduction followed by a return towards the original power, due to positive reactivity feedback from the negative moderator temperature coefficient. Increased peaking during the power increase may result in excessive local Linear Heat Rates (LHRs).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The most limiting static misalignment occurs when Bank 4 is fully inserted with one rod fully withdrawn (Bank 4 is 99 inches out of alignment with the rated Power Dependent Insertion Limit (PDIL). This event was bounded by the dropped full-length control rod event (Ref. 4).

Since the control rod drop incidents result in the most rapid approach to SAFDLs caused by a control rod misoperation, the accident analysis analyzed a single full-length control rod drop.

The above control rod misoperations may or may not result in an automatic reactor trip. In the case of the full-length rod drop, a prompt decrease in core average power and a distortion in radial power are initially produced, which, when conservatively coupled, result in a local power and heat flux increase, and a decrease in DNBR parameters.

The results of the control rod misoperation analysis show that during the most limiting misoperation events, no violations of the SAFDLs, fuel centerline temperature, or PCS pressure occur.

Control rod alignment satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2).

LCO

The limits on shutdown, regulating, and part-length rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the full-length control rods will be available and will be inserted to provide enough negative reactivity to shut down the reactor. The OPERABILITY requirements also ensure that the control rod banks maintain the correct alignment and that each full-length control rod is capable of being moved by its CRDM. The OPERABILITY requirement for the part-length rods is that they are fully withdrawn.

The requirement is to maintain the control rod alignment to within 8 inches between any control rod and all other rods in its group. To help ensure this requirement is met, the control rod position deviation alarm generated by either the PIP node or the SPI system, must be OPERABLE and provide an alarm when any control rod becomes misaligned > 8 inches from any other rod in its group. The safety analysis assumes a total misalignment from fully withdrawn to fully inserted. This case bounds the safety analysis for a single rod in any intermediate position.

BASES

LCO (continued)

The primary rod position indication system is considered OPERABLE, for purposes of this specification, if the digital position readout, the PPC display, or the cam operated position indication lights give positive indication of rod position. The secondary rod position indication system is considered OPERABLE if the magnetically operated reed switches are providing positive indication of rod position either via the plant process computer or taking direct readings of the output from the magnetic reed switches.

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

APPLICABILITY

The requirements on control rod 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 (e.g., trippability) and alignment of control 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 reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and regulating 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 PCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5, and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1

Rod position indication is required to allow verification that the rods are positioned and aligned as assumed in the safety analysis. If one rod position indication channel is inoperable for one or more control rods then SR 3.1.4.1 (rod position verification) is required to be performed once within 15 minutes following any rod motion in that group. This ensures that the rods are positioned as required.

BASES

ACTIONS (continued)

B.1

When the control rod deviation alarm is inoperable, performing SR 3.1.4.1, once within 15 minutes of movement of any control rod, ensures improper control rod alignments are identified before unacceptable flux distributions occur. The specified Completion Times take into account other information continuously available to the operator in the control room, so that during control rod movement, deviations can be detected, and the protection provided by the control rod and deviation circuit is not required.

C.1 and C.2

A full-length control rod may become misaligned, yet remain trippable. In this condition, the control rod can still perform its required function of adding negative reactivity should a reactor trip be necessary.

Regulating rod alignment can be restored by either aligning the misaligned rod(s) to within 8 inches of all other rods in its group or, aligning the misaligned rod's group to within 8 inches of the misaligned rod if allowed by the rod group insertion limits. Shutdown rod alignment can be restored by aligning the misaligned rod to within 8 inches of all other rods in its group.

If one control rod is misaligned by > 8 inches continued operation in MODES 1 and 2 may continue, provided, within 2 hours, peaking factors have been verified acceptable in accordance with SR 3.2.2.1, or the power is reduced to ≤ 75% RTP.

Xenon redistribution in the core starts to occur as soon as a rod becomes misaligned. Reducing THERMAL POWER to ≤ 75% RTP ensures acceptable power distributions are maintained.

BASES

ACTIONS

C.1 and C.2 (continued)

For small misalignments of the control rods, there is:

a. A small effect on the time dependent long term power distributions relative to those used in generating LCOs and Limiting Safety System Settings (LSSS) setpoints;

b. A negligible effect on the available SDM; and

c. A small effect on the ejected rod worth used in the accident analysis.

With a large control rod misalignment, however, this misalignment would cause distortion of the core power distribution. This distortion may, in turn, have a significant effect on the time dependent, long term power distributions relative to those used in generating LCOs and LSSS setpoints.

The effect on the available SDM and the ejected rod worth used in the accident analysis remains small.

In both cases, a 2 hour time period is sufficient to:

a. Identify cause of a misaligned rod;

b. Take appropriate corrective action to realign the rods; and

c. Minimize the effects of xenon redistribution.

The Palisades analysis for rod misalignment is bounded by a single dropped rod. Therefore, rod misalignments are limited to one rod being misaligned from its group. If a full-length control rod is untrippable, it is not available for reactivity insertion during a reactor trip. With an untrippable full-length control rod, meeting the insertion limits of LCO 3.1.5, "Shutdown and Part-Length Rod Group Insertion Limits," and LCO 3.1.6, "Regulating Rod Group Position Limits," does not ensure that adequate SDM exists and therefore, the Actions of Condition E must be met.

BASES

ACTIONS (continued)

D.1

Condition D is entered whenever it is discovered that a single full-length control rod cannot be moved by its operator yet the control rod is still capable of being tripped. Although the ability to move a full-length control rod is not an initial assumption used in the safety analyses, it does relate to full-length control rod OPERABILITY. The inability to move a full-length control rod by its operator may be indicative of a systemic failure (other than trippability) which could potentially affect other rods. Thus, declaring a full-length control rod inoperable in this instance is conservative since it limits the number of full-length control rods which cannot be moved by their operators to only one. The Completion Time to restore an inoperable control rod to OPERABLE status is stated as prior to entering MODE 2 following next MODE 3 entry. This Completion Time allows unrestricted operation in MODES 1 and 2 while conservatively preventing a reactor startup with an immovable full-length control rod.

E.1

If the Required Action or associated Completion Time of Condition A, Condition B, Condition C, or Condition D is not met; one or more control rods are inoperable for reasons other than Condition D; or two or more control rods are misaligned by > 8 inches, or two channels of control rod position indication are inoperable for one or more control rods, the plant is required to be brought to MODE 3. By being brought to MODE 3, the plant is brought outside its MODE of applicability. Continued operation is not allowed in the case of more than one control rod misaligned from any other rod in its group by > 8 inches, or two or more rods inoperable. This is because these cases may be indicative of a loss of SDM and power re-distribution, and a loss of safety function, respectively.

Also, if no rod position indication exists for one or more control rods, continued operation is not allowed because the safety analysis assumptions of rod position cannot be ensured.

When a Required Action cannot be completed within the required Completion Time, a controlled shutdown should be commenced. 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual control rod positions are within 8 inches of all other control rods in the group at a 12 hour Frequency allows the operator to detect a control rod that is beginning to deviate from its expected position. The specified Frequency takes into account other control rod position information that is continuously available to the operator in the control room, so that during control rod movement, deviations can be detected. Also protection can be provided by the control rod deviation alarm.

SR 3.1.4.2

OPERABILITY of two control rod position indicator channels is required to determine control rod positions, and thereby ensure compliance with the control rod alignment and insertion limits. Performance of a CHANNEL CHECK on the primary and secondary control rod position indication channels provides confidence in the accuracy of the rod position indication systems. The control rod "full in" and "full out" lights, which correspond to the lower electrical limit and the upper electrical limit respectively, provide an additional means for determining the control rod positions when the control rods are at either their fully inserted or fully withdrawn positions.

The 12 hour Frequency takes into consideration other information continuously available to the operator in the control room, so that during control rod movement, deviations can be detected, and protection can be provided by the control rod deviation alarm.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.3

Verifying each full-length control rod is trippable would require that each full-length control rod be tripped. In MODES 1 and 2, tripping each full-length control rod would result in radial or axial power tilts, or oscillations. Therefore, individual full-length control rods are exercised every 92 days to provide increased confidence that all full-length control rods continue to be trippable, even if they are not regularly tripped. A movement of 6 inches is adequate to demonstrate motion without exceeding the alignment limit when only one control rod is being moved. The 92 day Frequency takes into consideration other information available to the operator in the control room and other surveillances being performed more frequently, which add to the determination of OPERABILITY of the control rods. At any time, if a control rod(s) is inoperable, a determination of the trippability of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.4

Demonstrating the rod position deviation alarm is OPERABLE verifies the alarm is functional. The 92 day Frequency takes into account other information continuously available to the operator in the control room, so that during control rod movement, deviations can be detected.

SR 3.1.4.5

Performance of a CHANNEL CALIBRATION of each control rod position indication channel ensures the channel is OPERABLE and capable of indicating control rod position over the entire length of the control rod's travel with the exception of the secondary rod position indicating channel dead band near the bottom of travel. This dead band exists because the control rod drive mechanism housing seismic support prevents operation of the reed switches. Since this Surveillance must be performed when the reactor is shut down, an 18 month Frequency to be coincident with refueling outage was selected. Operating experience has shown that these components usually pass this Surveillance when performed at a Frequency of once every 18 months. Furthermore, the Frequency takes into account other surveillances being performed at shorter Frequencies, which determine the OPERABILITY of the control rod position indicating systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.6

Verification of full-length control rod drop times determines that the maximum control rod drop time is consistent with the assumed drop time used in that safety analysis (Ref. 2). The 2.5 second acceptance criteria is measured from the time the CRDM clutch is deenergized by the reactor protection system or test switch to 90% insertion. This time is bounded by that assumed in the safety analysis (Ref.2). Measuring drop times prior to reactor criticality, after reactor vessel head reinstallation, ensures that reactor internals and CRDMs will not interfere with full-length control rod motion or drop time and that no degradation in these systems has occurred that would adversely affect full-length control rod motion or drop time. Individual full-length control rods whose drop times are greater than safety analysis assumptions are not OPERABLE. This SR is performed prior to criticality, based on the need to perform this Surveillance under the conditions that apply during a plant outage and because of the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. FSAR, Section 5.1
2. FSAR, Section 14.1
3. FSAR, Section 14.4
4. FSAR, Section 14.6

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown and Part-Length Rod Group Insertion Limits

BASES

BACKGROUND

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

The Palisades Nuclear Plant design criteria (Ref. 1) and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors," contain the applicable criteria for these reactivity and power distribution design requirements. Limits on shutdown rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the reactivity limits, ejected rod worth, and SDM limits are preserved.

The shutdown rods are arranged into groups that are radially symmetric. Therefore, movement of the shutdown rod groups does not introduce radial asymmetries in the core power distribution. The shutdown and regulating rod groups provide the required reactivity worth for immediate reactor shutdown upon a reactor trip.

The Palisades Nuclear Plant has four part-length control rods installed. The part-length rods are required to remain completely withdrawn during power operation except during rod exercising performed in conjunction with SR 3.1.4.3. The part-length rods do not insert on a reactor trip.

The design calculations are performed with the assumption that the shutdown rod groups are withdrawn prior to the regulating rod groups. The shutdown rods can be fully withdrawn without the core going critical. This provides available negative reactivity for SDM in the event of boration errors. All control rod groups are controlled manually by the control room operator. During normal plant operation, the shutdown rod groups are fully withdrawn. The shutdown rod groups must be completely withdrawn from the core prior to withdrawing any regulating rods during an approach to criticality. The shutdown rod groups are then left in this position until the reactor is shut down.

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

BASES

APPLICABLE SAFETY ANALYSES

Accident analysis assumes that the shutdown rod groups are fully withdrawn any time the reactor is critical. This ensures that:

a. The minimum SDM is maintained; and

b. The potential effects of a control rod ejection accident are limited to acceptable limits.

Control rods are considered fully withdrawn at 128 inches, since this position places them in an insignificant reactivity worth region of the integral worth curve for each bank.

On a reactor trip, all full-length control rods (shutdown and regulating), except the most reactive rod, are assumed to insert into the core. The shutdown and regulating rod groups shall be at or above their insertion limits and available to insert the required amount of negative reactivity on a reactor trip signal. The regulating rods may be partially inserted in the core as allowed by LCO 3.1.6, "Regulating Rod Group Position Limits." The shutdown rod group insertion limit is established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)) following a reactor trip from full power. The combination of regulating rod and shutdown rods (less the most reactive rod, which is assumed to remain 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. 2). The shutdown rod group insertion limit also limits the reactivity worth of an ejected shutdown rod.

The acceptance criteria for addressing shutdown rods as well as regulating rod insertion limits and inoperability)or misalignment are that:

a. There be no violation of:

   1. Specified acceptable fuel design limits, or

   2. Primary Coolant System pressure boundary damage; and

b. The core remains subcritical after accident transients.

BASES

APPLICABLE SAFETY ANALYSES (continued)

As such, the shutdown and part-length rod group insertion limits affect safety analyses involving core reactivity, ejected rod worth, and SDM (Ref. 2). The part-length control rods have the potential to cause power distribution envelopes to be exceeded if inserted while the reactor is critical. Therefore, they must remain withdrawn in accordance with the limits of the LCO (Ref. 3).

The shutdown and part-length rod group insertion limits satisfy Criterion 2 of 10 CFR 50.36(c)(2).

LCO

The shutdown and part-length rod groups must be within their insertion limits any time the reactor is critical or approaching criticality. For a control rod group to be considered above its insertion limit, all rods in that group must be above the insertion limit. Maintaining the shutdown rod groups within their insertion limits ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. Maintaining the part-length rod group within its insertion limit ensures that the power distribution envelope is maintained.

APPLICABILITY

The shutdown and part-length rod groups must be within their insertion limits, with the reactor in MODES 1 and 2. In MODE 2 the Applicability begins anytime any regulating rod is withdrawn above 5 inches. 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. In MODE 4, 5, or 6, the shutdown rod groups are inserted in the core to at least the lower electrical limit and contribute to the SDM. In MODE 3 the shutdown rod groups may be withdrawn in preparation of a reactor startup. Refer to LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability has been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.3 (rod exercise test). Control rod exercising verifies the freedom of the rods to move, and requires the individual shutdown rods to move below the LCO limits for their group. Only the full-length rods are required to be tested by SR 3.1.4.3. The part-length rods may also be moved however, if a part-length rod is moved below the limit of the associated LCO, the Required Actions of Condition A must be taken.

BASES

APPLICABILITY (continued)

Positioning of an individual control rod within its group is addressed by LCO 3.1.4, "Control Rod Alignment."

ACTIONS

A.1

Prior to entering this condition, the shutdown and part-length rod groups were fully withdrawn. If a shutdown rod group is then inserted into the core, its potential negative reactivity is added to the core as it is inserted.

If one or more shutdown or part-length rods are not within limits, the affected rod(s) must be declared inoperable and the applicable Conditions and Required Actions of LCO 3.1.4 entered immediately. This Required Action is based on the recognition that the shutdown and part-length rods are normally withdrawn beyond their insertion limits and are capable of being moved by their control rod drive mechanism. Although the requirements of this LCO are not applicable during performance of the control rod exercise test, the inability to restore a control rod to within the limits of the LCO following rod exercising would be indicative of a problem affecting the OPERABILITY of the control rod. Therefore, entering the applicable Conditions and Required Actions of LCO 3.1.4 is appropriate since they provide the applicable compensatory measures commensurate with the inoperability of the control rod.

B.1

When Required Action A.1 cannot be met or completed within the required Completion Time, a controlled shutdown should be commenced. 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown and part-length rod groups are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown rods will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. Verification that the part-length rod groups are within their insertion limits ensures that they do not adversely affect power distribution requirements. This SR and Frequency ensure that the shutdown and part-length rod groups are withdrawn before the regulating rods are withdrawn during a plant startup.

Since control rod groups are positioned manually by the control room operator, verification of shutdown and part-length rod group position at a Frequency of 12 hours is adequate to ensure that the shutdown and part-length rod groups are within their insertion limits. Also, the 12 hour Frequency takes into account other information available to the operator in the control room for the purpose of monitoring the status of the shutdown and part-length rod groups.

REFERENCES

1. FSAR, Section 5.1
2. FSAR, Section 14.2
3. FSAR, Section 14.6

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Regulating Rod Group Position Limits

BASES

BACKGROUND

The insertion limits of the regulating rod groups are initial assumptions in all safety analyses that assume full-length rod insertion upon reactor trip. The insertion limits directly affect core power distributions, assumptions of available SDM, and initial reactivity insertion rate. The applicable criteria for these reactivity and power distribution design requirements are contained in the Palisades Nuclear Plant design criteria (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2).

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

The regulating rod groups operate with a predetermined amount of position overlap, in order to approximate a linear relation between rod worth and rod position (integral rod worth). The regulating rod groups are withdrawn and operate in a predetermined sequence. The group sequence and overlap limits are specified in the COLR.

The regulating rods are used for precise reactivity control of the reactor. The positions of the regulating rods are manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited to maintain specified acceptable fuel design limits, including limits that preserve the criteria specified in 10 CFR 50.46 (Ref. 2). Together, LCO 3.1.6; LCO 3.2.3, "QUADRANT POWER TILT (T_q)"; and LCO 3.2.4, "AXIAL SHAPE INDEX (ASI)," provide limits on control component operation and on monitored process variables to ensure the core operates within the linear heat rate (LCO 3.2.1, "Linear Heat Rate (LHR)") and radial peaking factor F_R^T and F_R^A (LCO 3.2.2, "Radial Peaking Factors) limits in the COLR.

BASES

BACKGROUND (continued)

Operation within the LHR limits given in the COLR prevents power peaks that would exceed the Loss Of Coolant Accident (LOCA) limits derived by the Emergency Core Cooling System analysis. Operation within the F_R^A and F_R^T limits given in the COLR prevents Departure from Nucleate Boiling (DNB) during a loss of forced reactor coolant flow accident. In addition to the LHR, F_R^A, and F_R^T limits, certain reactivity limits are preserved by regulating rod insertion limits. The regulating rod group insertion limits also restrict the ejected rod worth to the values assumed in the safety analysis and preserve the minimum required SDM in MODES 1 and 2.

The ejected rod case is limited to the reactivity worth for the highest worth rod ejected from the PDIL limit, thus limiting the maximum possible reactivity excursion.

The establishment of limiting safety system settings and LCOs requires that the expected long and short term behavior of the radial peaking factors be determined. The long term behavior relates to the variation of the steady state radial peaking factors with core burnup and is affected by the amount of rod insertion assumed, the portion of a burnup cycle over which such insertion is assumed, and the expected power level variation throughout the cycle. The short term behavior relates to transient perturbations to the steady state radial peaks, due to radial xenon redistribution. The magnitudes of such perturbations depend upon the expected use of the rods during anticipated power reductions and load maneuvering. Analyses are performed, based on the expected mode of operation of the Nuclear Steam Supply System (base loaded, maneuvering, etc.). The PDIL curve stated in the COLR dictates the acceptable regulating rod group positioning for anticipated power maneuvers and transient mitigation within the limits. The PDIL limitations stated in the COLR reflect the assumptions made in the safety analyses. This ensures that radial peaking is not violated during power level maneuvering or transient mitigation.

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

BASES

BACKGROUND (continued)

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 LOCA, loss of flow, ejected rod, or other accident requiring termination by a Reactor Protection System trip function.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation (Condition I) and anticipated operational occurrences (Condition II). The acceptance criteria for the regulating rod group position, ASI, and T_q LCOs are such as to preclude core power distributions from occurring that would violate the following fuel design criteria:

a. During a large break LOCA, the peak cladding temperature must not exceed a limit of 2200°F, (Ref. 2);

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

c. During an ejected rod accident, the fission energy input to the fuel must not exceed 280 cal/gm (Ref. 3); and

d. The rods must be capable of shutting down the reactor with a minimum required SDM, with the highest worth rod stuck fully withdrawn (Ref. 1).

Regulating rod group position, ASI, and T_q are process variables that together characterize and control the three dimensional power distribution of the reactor core.

Fuel cladding damage does not occur when the core is operated outside these LCOs during normal operation. However, fuel cladding damage could result, should an accident occur with simultaneous violation of one or more of these LCOs. Changes in the power distribution can cause increased power peaking and corresponding increased local LHRs.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SDM requirement is ensured by limiting the regulating and shutdown rod group insertion limits, so that the allowable inserted worth of the rods is such that sufficient reactivity is available to shut down the reactor to hot zero power. SDM assumes the maximum worth rod remains fully withdrawn upon trip (Ref. 4).

The most limiting SDM requirements for Mode 1 and 2 conditions at Beginning of Cycle (BOC) are determined by the requirements of several transients, e.g., Loss of Flow, etc. However, the most limiting SDM requirements for MODES 1 and 2 at End of Cycle (EOC) come from just one transient, Main Steam Line Break (MSLB). The requirements of the MSLB event at EOC for the full power and no load conditions are significantly larger than those of any other event at that time in cycle and, also, considerably larger than the most limiting requirements at BOC.

Although the most limiting SDM requirements at EOC are much larger than those at BOC, the available SDMs obtained via tripping the full-length control rods are substantially larger due to the much lower boron concentration at EOC. To verify that adequate SDMs are available throughout the cycle to satisfy the changing requirements, calculations are performed at both BOC and EOC. It has been determined that calculations at these two times in cycle are sufficient since the difference between available SDMs and the limiting SDM requirements are the smallest at these times in cycle. The measurement of full-length control rod bank worth performed as part of the Startup Testing Program demonstrates that the core has the expected shutdown capability. Consequently, adherence to LCO 3.1.5, "Shutdown and Part-Length Rod Group Insertion Limits," and LCO 3.1.6 provides assurance that the available SDM at any time in cycle will exceed the limiting SDM requirements at that time in cycle.

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

The regulating and shutdown rod insertion limits ensure that safety analyses assumptions for reactivity insertion rate, SDM, ejected rod worth, and power distribution peaking factors are preserved.

The regulating rod group position limits satisfy Criterion 2 of 10 CFR 50.36(c)(2).

BASES

LCO

The limits on regulating rod group 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 on trip. The overlap between regulating rod groups provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during regulating rod group motion. For a control rod group to be considered above its insertion limit, all rods in that group must be above the insertion limit.

The Power Dependent Insertion Limit (PDIL) alarm circuit is required to be OPERABLE for notification that the regulating rod groups are outside the required insertion limits. The Control Rod Out Of Sequence (CROOS) alarm circuit is required to be OPERABLE for notification that the rods are not within the required sequence and overlap limits. When the PDIL or the CROOS alarm circuit is inoperable, the verification of rod group positions is increased to ensure improper rod alignment is identified before unacceptable flux distribution occurs. The PDIL and CROOS alarms can be generated by either the synchro based Primary Indication Processor (PIP) node, or the reed switch based Secondary Position Indication (SPI) system since the SPI system, in conjunction with the host computer, is redundant to the PIP node in the task of control rod measurement, control rod monitoring and limit processing.

APPLICABILITY

The regulating rod group sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2. 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. SDM is preserved in MODES 3, 4, and 5 by adjustments to the soluble boron concentration.

The Applicability has been modified by a Note indicating the LCO requirement is suspended while performing SR 3.1.4.3 (rod exercise test). Control rod exercising verifies the freedom of the rods to move, and requires the individual regulating rods to move below the LCO limits which could violate the LCO for their group.

BASES

ACTIONS

A.1 and A.2

Operation beyond the insertion limit may result in a loss of SDM and excessive peaking factors. The insertion limit should not be violated during normal operation; this violation, however, may occur during transients when the operator is manually controlling the regulating rods in response to changing plant conditions.

When the regulating groups are inserted beyond the insertion limits, actions must be taken to either withdraw the regulating groups beyond the limits or to reduce THERMAL POWER to less than or equal to that allowed for the actual rod group position limit. Two hours provides a reasonable time to accomplish this, allowing the operator to deal with current plant conditions while limiting peaking factors to acceptable levels.

B.1

Operating outside the regulating rod group sequence and overlap limits specified in the COLR may result in excessive peaking factors. If the sequence and overlap limits are exceeded, the regulating rod groups must be restored to within the appropriate sequence and overlap. Two hours provides adequate time for the operator to restore the regulating rod group to within the appropriate sequence and overlap limits.

C.1

When the PDIL or the CROOS alarm circuit is inoperable, performing SR 3.1.6.1 once within 15 minutes following any rod motion ensures improper rod alignments are identified before unacceptable flux distributions occur.

D.1

When a Required Action cannot be completed within the required Completion Time, a controlled shutdown should be commenced. 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

With the PDIL alarm circuit OPERABLE, verification of each regulating rod group position every 12 hours is sufficient to detect rod positions that may approach the acceptable limits, and to provide the operator with time to undertake the Required Action(s) should the sequence or insertion limits be found to be exceeded.

The 12 hour Frequency also takes into account the indication provided by the PDIL alarm circuit and other information about rod group positions available to the operator in the control room.

SR 3.1.6.2

Demonstrating the PDIL alarm circuit OPERABLE verifies that the PDIL alarm circuit is functional. The 31 day Frequency takes into account other Surveillances being performed at shorter Frequencies that identify improper control rod alignments.

SR 3.1.6.3

Demonstrating the CROOS alarm circuit OPERABLE verifies that the CROOS alarm circuit is functional. The 31 day Frequency takes into account other Surveillances being performed at shorter Frequencies that identify improper control rod alignment.

REFERENCES

1. FSAR, Section 5.1
2. 10 CFR 50.46
3. FSAR, Section 14.16
4. FSAR, Section 14.4

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Special Test Exceptions (STE)

BASES

BACKGROUND

The primary purpose of this STE is to permit relaxation of existing LCOs to allow the performance of certain PHYSICS TESTS. These tests are conducted to determine control rod worths, SHUTDOWN MARGIN (SDM), and specific reactor core characteristics.

Section XI of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Processing Plants" (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 specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. Testing is required as an integral part of the design, fabrication, construction, and operation of the power plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59, "Changes, tests, and experiments" (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 design and analyses;

c. Verify assumptions used for predicting plant response;

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

e. Verify that operating and emergency procedures are adequate.

To accomplish these objectives, testing is required during startup and low power operation after each shutdown that involved an alteration of the fuel assemblies in the reactor core. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions, and that the core can be operated as designed (Ref. 4).

BASES

BACKGROUND (continued)

PHYSICS TESTS procedures are written and approved in accordance with the administrative processes for procedure controls. The procedures include all information necessary to permit a detailed execution of testing required to ensure that design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to power escalation.

Examples of PHYSICS TESTS include determination of critical boron concentration, full-length control rod group and individual control rod worths, reactivity coefficients, flux symmetry, and core power distribution.

APPLICABLE SAFETY ANALYSES

It is acceptable to suspend certain LCOs for PHYSICS TESTS because fuel damage criteria are not exceeded. Even if an accident occurs during a PHYSICS TEST with one or more LCOs suspended, fuel damage criteria are preserved because the limits on power distribution and shutdown capability are maintained during PHYSICS TESTS.

Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-1985 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits of 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. As long as the Linear Heat Rate (LHR) remains within its limit, fuel design criteria are preserved.

In this test, the following LCOs are suspended:

a. LCO 3.1.4, "Control Rod Alignment";

b. LCO 3.1.5, "Shutdown and Part-Length Rod Group Insertion Limits";

c. LCO 3.1.6, "Regulating Rod Group Position Limits"; and

d. LCO 3.4.2, "PCS Minimum Temperature for Criticality."

This STE places limits on allowable THERMAL POWER during PHYSICS TESTS assuring the LHR and the Departure from Nucleate Boiling (DNB) parameters will be maintained within limits. It also places limits on the amount of control rod worth required to be available for reactivity control when control rod worth measurements are performed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

SRs are conducted as necessary to ensure that reactor power and shutdown capability remain within limits during PHYSICS TESTS. Requiring ≥ 1% shutdown reactivity, based on predicted control rod worths, be available for trip insertion from the OPERABLE full-length control rod provides a high degree of assurance that shutdown capability is maintained for the most challenging postulated accident assuming all full-length control rods are inserted in the core. Since LCOs 3.1.5 and 3.1.6 are suspended, however, there is not the same degree of assurance during this test that the reactor would always be shut down if the highest worth full-length control rod was stuck out and calculational uncertainties or the estimated highest rod worth was not as expected (the single failure criterion is not met). This situation is judged acceptable, however, because specified acceptable fuel damage limits are still met. The risk of experiencing a stuck rod and subsequent criticality is reduced during this PHYSICS TEST exception by the requirements to determine rod positions every 2 hours; by the trip of each full-length control rod to be withdrawn 7 days prior to suspending the insert limit LCOs; and by ensuring that ≥ 1% shutdown reactivity is available based on predicted control rod worths (Ref. 5).

PHYSICS TESTS include measurement of core parameters or exercise of control components. Also involved are the shutdown and regulating rods, which affect power peaking and are required for shutdown of the reactor. The limits for insertion of these rod groups are specified for each fuel cycle in the COLR.

As described in LCO 3.0.7, compliance with Special Test Exceptions LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2) apply. Special Test Exception LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

This LCO relaxes the minimum primary coolant temperature at which the reactor may be made critical, permits individual full-length control rods and full-length control rod groups to be positioned outside of their normal alignment and insertion limits during the performance of PHYSICS TESTS such as those required to:

a. Measure control rod worths;

b. Measure control rod shadowing factors; and

c. Measure temperature and power coefficients.

BASES

LCO (continued)

This LCO specifies that a minimum amount of rod worth is immediately available for reactivity control when rod worth measurement tests are performed. This portion of the STE permits the periodic verification of the actual versus predicted control rod group worths.

The requirements of 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. THERMAL POWER is ≤ 2% RTP;

b. ≥ 1% shutdown reactivity, based on predicted control rod worth, is available for trip insertion; and

c. T_{ave} is ≥ 500°F.

APPLICABILITY

This LCO is applicable in MODE 2 because the reactor must be critical to perform the PHYSICS TESTS described in the LCO section.

ACTIONS

A.1

If THERMAL POWER exceeds 2% RTP, THERMAL POWER must be reduced to restore the additional thermal margin provided by the reduction. The 15 minute Completion Time ensures that prompt action shall be taken to reduce THERMAL POWER to within acceptable limits.

B.1

If < 1% shutdown reactivity is available for trip insertion, 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 ≥ 1% shutdown reactivity is achieved.

C.1

If the T_{ave} requirement is not met, T_{ave} must be restored. The 15 minutes Completion Time ensures that prompt action shall be taken to raise T_{ave} within the required limit.

BASES

ACTIONS (continued)

D.1

If Required Actions of Condition A, Condition B, or Condition C cannot be completed within the required Completion Time, PHYSICS TESTS must be suspended within 1 hour. Allowing 1 hour for suspending PHYSICS TESTS allows the operator sufficient time to change any abnormal rod configuration back to within the limits of LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6, or to restore Primary Coolant System (PCS) temperature to within the limits of LCO 3.4.2.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verifying that THERMAL POWER is ≤ 2% RTP as specified in the PHYSICS TEST procedure and required by the safety analysis, ensures that adequate LHR and DNB parameter margins are maintained while LCOs are suspended. The 1 hour Frequency is sufficient, based on the slow rate of power change and increased operational controls in place during PHYSICS TESTS.

SR 3.1.7.2

Verifying T_{ave} ≥ 500°F during the PHYSICS TEST ensures that T_{ave} remains in an analyzed range while the LCOs are suspended. The 1 hour Frequency is sufficient, based on the slow rate of change and increased operational controls in place during PHYSICS TESTS.

SR 3.1.7.3

Verification that ≥ 1% shutdown reactivity is available for trip insertion is performed by a reactivity balance calculation, considering the following reactivity effects:

a. PCS boron concentration;

b. Control rod group position;

c. PCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.3 (continued)

e. Xenon concentration; and

f. Isothermal Temperature Coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because reactor power is maintained below 2% RTP, and for most of the PHYSIC TESTS below the point of adding heat the fuel temperature will be changing at the same rate as the PCS.

The Frequency of 24 hours is based on the generally slow change in boron concentration and on the low probability of an accident occurring without the SDM established by LCO 3.1.5.

REFERENCES

1. 10 CFR 50, Appendix B, Section XI

2. 10 CFR 50.59

3. Regulatory Guide 1.68, Revision 2, August 1978

4. ANSI/ANS-19.6.1-1985, December 13, 1985

5. FSAR, Chapter 13

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Linear Heat Rate (LHR)

BASES

BACKGROUND

The purpose of this LCO is to limit the core power distribution to the initial values assumed in the accident analyses. Operation within the limits imposed by this LCO either limits or prevents potential fuel cladding failures that could breach the primary fission product barrier and release fission products to the primary coolant in the event of a Loss Of Coolant Accident (LOCA), loss of flow accident, ejected control rod accident, or other postulated accident requiring termination by a Reactor Protection System trip function. This LCO limits the amount of damage to the fuel cladding during an accident by ensuring that the plant is operating within acceptable bounding conditions at the onset of a transient.

Methods of controlling the power distribution include:

a. Using control rods to alter the axial power distribution;

b. Decreasing control rod insertion by boration, thereby improving the radial power distribution; and

c. Correcting off optimum conditions (e.g., a control rod drop or misoperation of the plant) that cause margin degradations.

The core power distribution is controlled so that, in conjunction with other core operating parameters (e.g., control rod insertion and alignment limits), the power distribution satisfies this LCO. The limiting safety system settings and this LCO are based on the accident analyses (Refs. 1 and 2), so that specified acceptable fuel design limits are not exceeded as a result of Anticipated Operational Occurrences (AOOs), and the limits of acceptable consequences are not exceeded for other postulated accidents.

Limiting power distribution changes over time also minimizes the xenon distribution changes, which is a significant factor in controlling the axial power distribution.

Power distribution is a product of multiple parameters, various combinations of which may produce acceptable power distributions.

BASES

BACKGROUND (continued)

The limits on LHR, Assembly Radial Peaking Factor (F_R^A), Total Radial Peaking Factor (F_R^T), QUADRANT POWER TILT (T_q), and AXIAL SHAPE INDEX (ASI), which are obtained directly from the core reload analysis, ensure compliance with the safety limits on LHR and Departure from Nucleate Boiling Ratio (DNBR).

Either of the two core power distribution monitoring systems, the Incore Alarm System or the Excore Monitoring System, provides adequate monitoring of the core power distribution and is capable of verifying that the LHR is within its limits. The Incore Alarm System performs this function by continuously monitoring the local power at many points throughout the core and comparing the measurements to predetermined setpoints above which the limit on LHR could be exceeded. The Excore Monitoring System performs this function by providing comparison of the measured core ASI with predetermined ASI limits based on incore measurements. An Excore Monitoring System Allowable Power Level (APL), which may be less than RATED THERMAL POWER, and an additional restriction on T_q, are applied when using the Excore Monitoring System to ensure that the ASI limits adequately restrict the LHR to less than the limiting values.

In conjunction with the use of the Excore Monitoring System for monitoring LHR and in establishing ASI limits, the following assumptions are made:

a. The control rod insertion limits of LCO 3.1.5, "Shutdown and Part-Length Rod Group Insertion Limits," and LCO 3.1.6, "Regulating Rod Group Position Limits," are satisfied;

b. The additional T_q restriction of SR 3.2.1.6 is satisfied; and

c. Radial Peaking Factors, F_R^A and F_R^T, do not exceed the limits of LCO 3.2.2.

The limitations on the Radial Peaking Factors provided in the COLR ensure that the assumptions used in the analysis for establishing the LHR limits and Limiting Safety System Settings (LSSS) remain valid during operation at the various allowable control rod group insertion limits.

BASES

BACKGROUND (continued)

The Incore Alarm System continuously provides a direct measure of the LHR and the Radial Peaking factors. It also provides alarms that have been established for the individual incore detector segments, ensuring that the peak LHRs are maintained within the limits specified in the COLR. The setpoints for these alarms include tolerances, set in conservative directions, for:

a. A measurement calculational uncertainty factor (as identified in the COLR);

b. An engineering uncertainty factor of 1.03; and

c. A THERMAL POWER measurement uncertainty factor of 1.02.

The measurement uncertainties associated with LHR, F_R^A and F_R^T are based on a statistical analysis performed on power distribution benchmarking results. The COLR includes the applicable measurement uncertainties for fresh and depleted incore detector usage. The engineering and THERMAL POWER uncertainties are incorporated in the power distribution calculation performed by the fuel vendor.

The excore power distribution monitoring system consists of Power Range Channels 5 through 8. The power range channels monitor neutron flux from 0 to 125 percent full power. They are arranged symmetrically around the reactor core to provide information on the radial and axial flux distributions.

The power range detector assembly consists of two uncompensated ion chambers for each channel. One detector extends axially along the lower half of the core while the other, which is located directly above it, monitors flux from the upper half of the core. The DC current signal from each of the ion chambers is fed directly to the control room drawer assembly without pre-amplification. Each excore detector supplies data to a Thermal Margin Monitor (TMM). Each TMM uses these excore signals to calculate Axial Shape Index (ASI) on a continuous basis.

ASI can be defined as the compensated ratio of power developed in the upper and lower sections of the core. The TMM takes the excore detector signals and develops a power ratio (YE) that describes the distribution of neutron flux developed in the core by the formula:

$$YE = (L - U)/(L + U)$$

Where L is the lower excore segment flux, and U is the upper excore segment flux.

BASES

BACKGROUND (continued)

The excore detectors which are located within the concrete biological shield of the reactor must be compensated for the phenomenon of shape annealing. Shape annealing factors are developed to correct the excore readings for neutron attenuation from the core periphery to the excore detector locations. This accounts for any material that would cause neutron attenuation within the detector path such as: concrete, structural steel and so forth. This allows the excore detectors to represent an accurate measurement of the core power distribution. Shape annealing has been found to be a linear relationship which can be correlated to the Axial Offset (AO) as determined by an Incore Detector System to the raw readings seen by the excore detectors.

Reactor Engineering has developed shape annealing factors for each individual Excore detector. The TMM uses the above calculated power ratio and the appropriate shape annealing factor to determine the ASI value for an individual excore detector channel.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation (Condition 1) or AOOs (Condition 2) (Ref. 3). The power distribution and control rod insertion and alignment LCOs preclude core power distributions that violate the following fuel design criteria:

a. During a LOCA, peak cladding temperature must not exceed 2200°F (Ref. 4);

b. During a loss of flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition (Ref. 3).

c. During an ejected rod accident, the fission energy input to the fuel must not exceed 280 cal/gm; and

d. The full-length 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 power density at any point in the core must be limited to maintain the fuel design criteria (Ref. 4). This is accomplished by maintaining the power distribution and primary coolant conditions so that the peak LHR and DNB parameters are within operating limits supported by accident analyses (Ref. 1), with due regard for the correlations between measured quantities, the power distribution, and uncertainties in determining the power distribution.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Fuel cladding failure during a LOCA is limited by restricting the maximum linear heat generation rate so that the peak cladding temperature does not exceed 2200°F (Ref. 4). High peak cladding temperatures are assumed to cause severe cladding failure by oxidation due to a Zircaloy water reaction.

The LCOs governing LHR, ASI, and the Primary Coolant System Operation ensure that these criteria are met as long as the core is operated within the LHR, ASI, F_R^A, F_R^T, and T_q limits. The latter are process variables that characterize the three dimensional power distribution of the reactor core. Operation within the limits for these variables ensures that their actual values are within the ranges used in the accident analyses.

Fuel cladding damage does not necessarily occur while the plant is operating at conditions outside the limits of these LCOs during normal operation. Fuel cladding damage could result, however, if an accident occurs from initial conditions outside the limits of these LCOs. The potential for fuel cladding damage exists because changes in the power distribution can cause increased power peaking and can correspondingly increase local LHR.

The Incore Alarm System provides for monitoring of LHR, radial peaking factors, and QUADRANT POWER TILT to ensure that fuel design conditions and safety analysis assumptions are maintained. The Incore Alarm System is also utilized to determine the target AXIAL OFFSET (AO) and to determine the Allowable Power Level (APL) when using the excore detectors.

The Excore Monitoring System provides for monitoring of ASI and QUADRANT POWER TILT to ensure that fuel design conditions and safety analysis assumptions are maintained.

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

LCO

The power distribution LCO limits are based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. The power distribution LCO limits, except T_q, are provided in the COLR. The limitation on the LHR in the peak power fuel rod at the peak power elevation Z ensures that, in the event of a LOCA, the peak temperature of the fuel cladding does not exceed 2200°F.

BASES

LCO (continued)

The LCO requires that LHR be maintained within the limits specified in the COLR and either the Incore Alarm System or Excore Monitoring System be OPERABLE to monitor LHR. When using the Incore Alarm System, the LHR is not considered to be out of limits until there are four or more incore detectors simultaneously in alarm. When using the Excore Monitoring System, LHR is considered within limits when the conditions are acceptable for use of the Excore Monitoring System and the associated ASI and T_q limits specified in the SRs are met.

To be considered OPERABLE, the Incore Alarm System must have at least 160 of the 215 possible incore detectors OPERABLE and 2 incore detectors per axial level per core quadrant OPERABLE. In addition, the plant process computer must be OPERABLE and the required alarm setpoints entered into the plant computer.

To be considered OPERABLE, the Excore Monitoring System must have been calibrated with OPERABLE incore detectors, the ASI must not have been out of limits for the last 24 hours, and THERMAL POWER must be less than the APL.

APPLICABILITY

In MODE 1 with THERMAL POWER > 25% RTP, power distribution must be maintained within the limits assumed in the accident analysis to ensure that fuel damage does not result following an AOO. In MODE 1 with THERMAL POWER ≤ 25% RTP, and in other MODES, this LCO does not apply because there is not sufficient THERMAL POWER to require a limit on the core power distribution, and because ample thermal margin exists to ensure that the fuel integrity is not jeopardized and safety analysis assumptions remain valid.

ACTIONS

A.1

There are three acceptable methods for verifying that LHR is within limits. The LCO requires monitoring by either an OPERABLE Incore Alarm System or an OPERABLE Excore Monitoring System. When both of the required systems are inoperable, Condition B allows for monitoring by taking manual readings of the incore detectors. Any of these three methods may indicate that the LHR is not within limits. With the LHR exceeding its limit, excessive fuel damage could occur following an accident. In this Condition, prompt action must be taken to restore the LHR to within the specified limits. One hour to restore the LHR to within its specified limits is reasonable and ensures that the core does not continue to operate in this Condition. The 1 hour Completion Time also allows the operator sufficient time for evaluating core conditions and for initiating proper corrective actions.

BASES

ACTIONS (continued)

B.1 and B.2

With the Incore Alarm System inoperable for monitoring LHR and the Excore Monitoring System inoperable for monitoring LHR, THERMAL POWER must be reduced to ≤ 85% RTP within 2 hours. Operation at ≤ 85% RTP ensures that ample thermal margin is maintained. A 2 hour Completion Time is adequate to achieve the required plant condition without challenging plant systems. Additionally, with the Incore Alarm and Excore Monitoring Systems inoperable, LHR must be verified to be within limits within 4 hours, and every 2 hours thereafter by manually collecting incore detector readings at the terminal blocks in the control room utilizing a suitable signal detector. The manual readings shall be taken on a minimum of 10 individual detectors per quadrant (to include a total of 160 detectors in a 10 hour period). The time interval of 2 hours and the minimum of 10 detectors per quadrant are sufficient to maintain adequate surveillance of the power distribution to detect significant changes until the monitoring systems are returned to service.

C.1

If the Required Action and associated Completion Time are not met, THERMAL POWER must be reduced to ≤ 25% RTP. This reduced power level ensures that the core is operating within its thermal limits and places the core in a conservative condition. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reach ≤ 25% RPT from full power MODE 1 conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

The Incore Alarm System provides continuous monitoring of LHR through the plant computer. The plant computer is used to generate alarm setpoints that are based on measured margin to allowed LHR. As the incore detectors are read by the plant computer, they are continuously compared to the alarm setpoints. If the Incore Alarm System LHR monitoring function is inoperable, excore detectors or manual recordings of the incore detector readings may be used to monitor LHR. Periodically monitoring LHR ensures that the assumptions made in the Safety Analysis are maintained. This SR is modified by a Note that states that the SR is only required to be met when the Incore Alarm System is being used to monitor LHR. The 12 hour Frequency is consistent with an SR which is to be performed each shift.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.2

Continuous monitoring of the LHR is provided by the Incore Alarm System which provides adequate monitoring of the core power distribution and is capable of verifying that the LHR does not exceed its specified limits.

Performance of this SR verifies the Incore Alarm System can accurately monitor LHR by ensuring the alarm setpoints are based on a measured power distribution. Therefore, they are only applicable when the Incore Alarm System is being used to determine the LHR.

The alarm setpoints must be initially adjusted following each fuel loading prior to operation above 50% RTP, and periodically adjusted every 31 Effective Full Power Days (EFPD) thereafter. A 31 EFPD Frequency is consistent with the historical testing frequency of the reactor monitoring system. The SR is modified by a Note which requires the SR to be met only when the Incore Alarm System is being used to determine LHR.

SR 3.2.1.3

SR 3.2.1.3 requires, prior to initial use of the excore LHR monitoring function, verification that the absolute difference of the measured ASI and the target ASI has been $\leq$ 0.05 for each OPERABLE channel for the last 24 hours using the previous 24 hourly recorded values. Performance of this SR verifies that plant conditions are acceptable for the Excore Monitoring System to accurately monitor the LHR (Ref. 5). The prior to initial use verification identifies that there have been no significant power distribution anomalies while using other monitoring methods, e.g., the incore detectors, which may affected the ability of the excore detectors to monitor LHR.

The SR is modified by a Note that states that the SR is only required to be met when the Excore Monitoring System is being used to monitor LHR. Failure of this SR prevents the Excore Monitoring System from being considered OPERABLE for monitoring of LHR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.4

SR 3.2.1.4 requires verification that THERMAL POWER is less than or equal to the Allowable Power Level (APL) which is limited to not more than 10% greater than the THERMAL POWER at which the APL was last determined. Performance of this SR also verifies that plant conditions are acceptable for the Excore Monitoring System to accurately monitor the LHR (Ref. 5). The 1 hour Frequency is based on engineering judgement and the need to assure that conditions remain acceptable for use of the Excore Monitoring System to monitor LHR.

The SR is modified by a Note that states that the SR is only required to be met when the Excore Monitoring System is being used to monitor LHR. Failure of this SR prevents the Excore Monitoring System from being considered OPERABLE for monitoring of LHR.

SR 3.2.1.5

SR 3.2.1.5 requires verification that the absolute difference of the measured ASI and the target ASI is $\leq$ 0.05 every hour. This must be verified on at least 3 of the 4, 2 of the 3, or 2 of the 2 OPERABLE channels, whichever is the applicable case. However, any otherwise OPERABLE channel which indicates an absolute difference of > 0.05 must be considered out of limits. Performance of this SR verifies that plant conditions are acceptable for the Excore Monitoring System to be used to assure LHR is within limits (Ref. 5). The 1 hour Frequency is appropriate because the excore detectors input neutron flux information into the ASI calculation which is normally performed automatically and continuously.

The SR is modified by a Note that states that the SR is only required to be met when the Excore Monitoring System is being used to monitor LHR. Failure of this SR (when using an OPERABLE Excore Monitoring System) is a failure to verify that LHR is within limits and is therefore considered a failure to meet the LCO due to LHR not within limits as determined by the Excore Monitoring System.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.6

SR 3.2.1.6 requires verification that the QUADRANT POWER TILT is ≤ 0.03. Performance of this SR also verifies that plant conditions are acceptable for the Excore Monitoring System to be used to assure LHR is within limits (Ref. 5). The 24 hour Frequency is based on engineering judgement and the need to identify adverse trends in these parameters prior to their affecting the ability of the Excore Monitoring System to monitor LHR.

The SR is modified by a Note that states that the SR is only required to be met when the Excore Monitoring System is being used to monitor LHR. Failure of this SR (when using an OPERABLE Excore Monitoring System) is a failure to verify that LHR is within limits and is therefore considered a failure to meet the LCO due to LHR not within limits as determined by the Excore Monitoring System.

REFERENCES

1. FSAR, Chapter 14
2. FSAR, Chapter 6
3. FSAR, Section 5.1
4. 10 CFR 50.46
5. Safety Evaluation Report for Palisades Nuclear Plant Operating License Amendment No. 68, Section 4, dated December 8, 1981

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 AXIAL SHAPE INDEX (ASI)

BASES

BACKGROUND

The Background section for Bases B 3.2.1, "Linear Heat Rate," is applicable to these Bases, with the following addition:

The Excore Monitoring System ASI alarm function consists of four channels. At least two channels of the ASI alarm function are necessary to verify that ASI is within limits. With one or more excore monitoring channels measured ASI differing from the incore measured AO by > 0.02 under steady state operating conditions, the ASI monitoring channel alarm setpoint may be adjusted to compensate for this deviation. This ensures that fuel design parameters can continue to be accurately monitored and not exceeded when the incore/excore alignment is not within normal tolerances. This may occur when the calibration cannot be performed or the alignment problem exists after the calibration.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section for Bases B 3.2.1 is applicable to these Bases.

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

LCO

The power distribution LCO limits are based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. These power distribution LCO limits, except T_q, are provided in the COLR. The limitation on ASI ensures that the assumed axial power profiles used in the development of the inlet temperature LCO bound the measured axial power profile.

The limitation on ASI, along with the limitations of LCO 3.3.1, "Reactor Protective System Instrumentation," represents a conservative envelope of operating conditions consistent with the assumptions that have been analytically demonstrated adequate for maintaining an acceptable minimum DNBR throughout all AOOs. Operation of the core with conditions within the specified limits ensures that an acceptable minimum margin from DNB conditions is maintained in the event of any AOO.

BASES

APPLICABILITY

In MODE 1 with THERMAL POWER > 25% RTP, power distribution must be maintained within the limits assumed in the accident analyses to ensure that fuel damage does not result following an AOO. In MODE 1 with THERMAL POWER ≤ 25% RTP, and in other MODES, this LCO does not apply because there is not sufficient THERMAL POWER to require a limit on the core power distribution, and because ample thermal margin exists to ensure that the fuel integrity is not jeopardized and safety analysis assumptions remain valid.

ACTIONS

A.1

Operating the core within ASI limits specified in the COLR and within the limits of LCO 3.3.1 ensures an acceptable margin for DNB and for maintaining local power density in the event of an AOO. Maintaining ASI within limits also ensures that the limits of 10 CFR 50.46 are not exceeded during accidents. The Required Actions to restore ASI must be completed within 2 hours to limit the duration the plant is operated outside the initial conditions assumed in the accident analyses. In addition, this Completion Time is sufficiently short that the xenon distribution in the core cannot change significantly.

B.1

If the Required Action and associated Completion Time are not met, core power must be reduced. Reducing THERMAL POWER to ≤ 25% RTP ensures that the core is operating farther from thermal limits and places the core in a conservative condition. Four hours is a reasonable amount of time, based on operating experience, to reduce THERMAL POWER to ≤ 25% RTP in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

Verifying that the ASI is within the limits specified in the COLR ensures that the core is not approaching DNB conditions. ASI is determined from excore detector readings which are calibrated using incore detector measurements (Ref. 1). Calibration factors are determined using incore measurements and an incore analysis computer program (Ref. 2). ASI is normally calculated and compared to the alarm setpoints continuously and automatically. Therefore, this SR only requires verification that alarms do not indicate an excessive ASI. If the Excore Monitoring System ASI Alarm function is inoperable, excore detector or incore indications may be used to monitor ASI. A Frequency of 12 hours is adequate for the operator to identify trends in conditions that result in an approach to the ASI limits, because the mechanisms that affect the ASI, such as xenon redistribution or control rod drive mechanism malfunctions, cause the ASI to change slowly and should be discovered before the limits are exceeded.

REFERENCES

1. FSAR, Section 7.4.2.2

2. FSAR, Section 7.6.2.4

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protective System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor trip to protect against violating the acceptable fuel design limits and breaching the reactor coolant pressure boundary during Anticipated Operational Occurrences (AOOs). By tripping the reactor, the RPS also assists the Engineered Safety Features (ESF) systems in mitigating accidents.

The protection and monitoring systems have been designed to ensure safe operation of the reactor. This is achieved by specifying Limiting Safety System Settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters and equipment performance.

The LSSS, defined in this Specification as the Allowable Values, 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 one or more times during the plant life, the acceptable limits are:

- The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling;
- Fuel centerline melting shall not occur; and
- The Primary Coolant System (PCS) pressure SL of 2750 psia shall not be exceeded.

Maintaining the parameters within the above values ensures that the offsite dose will be within the 10 CFR 50 (Ref. 1) and 10 CFR 100 (Ref. 2) criteria during AOOs.

BASES

BACKGROUND (continued)

Accidents are events that are analyzed even though they are not expected to occur during the plant life. The acceptable limit during accidents is that the offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 (Ref. 2) limits. Different accident categories allow a different fraction of these limits based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RPS is segmented into four interconnected modules. These modules are:

- Measurement channels;
- RPS trip units;
- Matrix Logic; and
- Trip Initiation Logic.

This LCO addresses measurement channels and RPS trip units. It also addresses the automatic bypass removal feature for those trips with Zero Power Mode bypasses. The RPS Logic and Trip Initiation Logic are addressed in LCO 3.3.2, "Reactor Protective System (RPS) Logic and Trip Initiation." The role of the measurement channels, RPS trip units, and RPS Bypasses is discussed below.

Measurement Channels

Measurement channels, consisting of pressure switches, field transmitters, or process sensors and associated instrumentation, provide a measurable electronic signal based upon the physical characteristics of the parameter being measured.

With the exception of Hi Startup Rate, which employs two instrument channels, and Loss of Load, which employs a single pressure sensor, four identical measurement channels with electrical and physical separation are provided for each parameter used in the direct generation of trip signals. These are designated channels A through D. Some measurement channels provide input to more than one RPS trip unit within the same RPS channel. In addition, some measurement channels may also be used as inputs to Engineered Safety Features (ESF) bistables, and most provide indication in the control room.

BASES

BACKGROUND

Measurement Channels (continued)

In the case of Hi Startup Rate and Loss of Load, where fewer than four sensor channels are employed, the reactor trips provided are not relied upon by the plant safety analyses. The sensor channels do however, provide trip input signals to all four RPS channels.

When a channel monitoring a parameter exceeds a predetermined setpoint, indicating an abnormal condition, the bistable monitoring the parameter in that channel will trip. Tripping two or more channels of bistable trip units monitoring the same parameter de-energizes Matrix Logic, (addressed by LCO 3.3.2) which in turn de-energizes the Trip Initiation Logic. This causes all four DC clutch power supplies to de-energize, interrupting power to the control rod drive mechanism clutches, allowing the full length control rods to insert into the core.

For those trips relied upon in the safety analyses, three of the four measurement and trip unit channels can meet the redundancy and testability of GDC 21 in 10 CFR 50, Appendix A (Ref. 1). This LCO requires, however, that four channels be OPERABLE. The fourth channel provides additional flexibility by allowing one channel to be removed from service (trip channel bypassed) for maintenance or testing while still maintaining a minimum two-out-of-three logic.

Since no single failure will prevent a protective system actuation, this arrangement meets the requirements of IEEE Standard 279-1971 (Ref. 3).

Most of the RPS trips are generated by comparing a single measurement to a fixed bistable setpoint. Two trip Functions, Variable High Power Trip and Thermal Margin Low Pressure Trip, make use of more than one measurement to provide a trip.

The required RPS Trip Functions utilize the following input instrumentation:

- Variable High Power Trip (VHPT)

  The VHPT uses Q Power as its input. Q Power is the higher of NI power from the power range NI drawer and primary calorimetric power (ΔT power) based on PCS hot leg and cold leg temperatures. The measurement channels associated with the VHPT are the power range excore channels, and the PCS hot and cold leg temperature channels.

BASES

BACKGROUND

Measurement Channels

- Variable High Power Trip (VHPT) (continued)

  The Thermal Margin Monitors provide the complex signal processing necessary to calculate the TM/LP trip setpoint, VHPT trip setpoint and trip comparison, and Q Power calculation. On power decreases the VHPT setpoint tracks power levels downward so that it is always within a fixed increment above current power, subject to a minimum value.

  On power increases, the trip setpoint remains fixed unless manually reset, at which point it increases to the new setpoint, a fixed increment above Q Power at the time of reset, subject to a maximum value. Thus, during power escalation, the trip setpoint must be repeatedly reset to avoid a reactor trip.

- High Startup Rate Trip

  The High Startup Rate trip uses the wide range Nuclear Instruments (NIs) to provide an input signal. There are only two wide range NI channels. The wide range channel signal processing electronics are physically mounted in RPS cabinet channels C (NI-1/3) and D (NI-2/4). Separate bistable trip units mounted within the NI-1/3 wide range channel drawer supply High Startup Rate trip signals to RPS channels A and C. Separate bistable trip units mounted within the NI-2/4 wide range channel drawer provide High Startup Rate trip signals to RPS channels B and D.

- Low Primary Coolant Flow Trip

  The Low Primary Coolant Flow Trip utilizes 16 flow measurement channels which monitor the differential pressure across the primary side of the steam generators. Each RPS channel, A, B, C, and D, receives a signal which is the sum of four differential pressure signals. This totalized signal is compared with a setpoint in the RPS Low Flow bistable trip unit for that RPS channel.

BASES

BACKGROUND

Measurement Channels (continued)

- Low Steam Generator Level Trips

  There are two separate Low Steam Generator Level trips, one for each steam generator. Each Low Steam Generator Pressure trip monitors four level measurement channels for the associated steam generator, one for each RPS channel.

- Low Steam Generator Pressure Trips

  There are also two separate Low Steam Generator Pressure trips, one for each steam generator. Each Low Steam Generator Pressure trip monitors four pressure measurement channels for the associated steam generator, one for each RPS channel.

- High Pressurizer Pressure Trip

  The High Pressurizer Pressure Trip monitors four pressurizer pressure channels, one for each RPS channel.

- Thermal Margin Low Pressure (TM/LP) Trip

  The TM/LP Trip utilizes bistable trip units. Each of these bistable trip units receives a calculated trip setpoint from the Thermal Margin Monitor (TMM) and compares it to the measured pressurizer pressure signal. The TM/LP setpoint is based on Q power (the higher of NI power from the power range NI drawer, or ΔT power, based on PCS hot leg and cold leg temperatures) pressurizer pressure, PCS cold leg temperature, and Axial Shape Index. The TMM provide the complex signal processing necessary to calculate the TM/LP trip setpoint, TM/LP trip comparison signal, and Q Power.

BASES

BACKGROUND

Measurement Channels (continued)

- Loss of Load Trip

  The Loss of Load trip uses a single pressure switch, 63/AST-2, in the turbine auto stop oil circuit to sense a turbine trip for input to all four RPS auxiliary trip units. The Loss of Load Trip is actuated by turbine auxiliary relays 305L and 305R. Relay 305L provides input to RPS channels A and C; 305R to channels B and D. Relays 305L and 305R are energized on a turbine trip. Their inputs are the same as the inputs to the turbine solenoid trip valve, 20ET.

  If a turbine trip is generated by loss of auto stop oil pressure, auto stop oil pressure switch 63/AST-2 will actuate relays 305L and 305R and generate a reactor trip. If a turbine trip is generated by an input to the solenoid trip valve, relays 305L and 305R, which are wired in parallel, will also be actuated and will generate a reactor trip.

- Containment High Pressure Trip

  The Containment High Pressure Trip is actuated by four pressure switches, one for each RPS channel.

- Zero Power Mode Bypass Automatic Removal

  The Zero Power Bypass allows manually bypassing (i.e., disabling) four reactor trip functions, Low PCS Flow, Low SG A Pressure, Low SG B Pressure, and TM/LP (low PCS pressure), when reactor power (as indicated by the wide range nuclear instrument channels) is below 10^{-4}%. This bypassing is necessary to allow RPS testing and control rod drive mechanism testing when the reactor is shutdown and plant conditions would cause a reactor trip to be present.

  The Zero Power Mode Bypass removal interlock uses the wide range nuclear instruments (NIs) as measurement channels. There are only two wide range NI channels. Separate bistables are provided to actuate the bypass removal for each RPS channel. Bistables in the NI-1/3 channel provide the bypass removal function for RPS channels A and C; bistables in the NI-2/4 channel for RPS channels B and D.

BASES

BACKGROUND (continued)

Several measurement instrument channels provide more than one required function. Those sensors shared for RPS and ESF functions are identified in Table B 3.3.1-1. That table provides a listing of those shared channels and the Specifications which they affect.

RPS Trip Units

Two types of RPS trip units are used in the RPS cabinets; bistable trip units and auxiliary trip units:

A bistable trip unit receives a measured process signal from its instrument channel and compares it to a setpoint; the trip unit actuates three relays, with contacts in the Matrix Logic channels, when the measured signal is less conservative than the setpoint. They also provide local trip indication and remote annunciation.

An auxiliary trip unit receives a digital input (contacts open or closed); the trip unit actuates three relays, with contacts in the Matrix Logic channels, when the digital input is received. They also provide local trip indication and remote annunciation.

Each RPS channel has four auxiliary trip units and seven bistable trip units.

The contacts from these trip unit relays are arranged into six coincidence matrices, comprising the Matrix Logic. If bistable trip units monitoring the same parameter in at least two channels trip, the Matrix Logic will generate a reactor trip (two-out-of-four logic).

Four of the RPS measurement channels provide contact outputs to the RPS, so the comparison of an analog input to a trip setpoint is not necessary. In these cases, the bistable trip unit is replaced with an auxiliary trip unit. The auxiliary trip units provide contact multiplication so the single input contact opening can provide multiple contact outputs to the coincidence logic as well as trip indication and annunciation.

BASES

BACKGROUND

RPS Trip Units (continued)

Trips employing auxiliary trip units include the VHPT, which receives contact inputs from the Thermal Margin Monitors; the High Startup Rate trip which employs contact inputs from bistables mounted in the two wide range drawers; the Loss of Load Trip which receives contact inputs from one of two auxiliary relays which are operated by a single switch sensing turbine auto stop oil pressure; and the Containment High Pressure (CHP) trip, which employs containment pressure switch contacts.

There are four RPS trip units, designated as channels A through D, each channel having eleven trip units, one for each RPS Function. Trip unit output relays de-energize when a trip occurs.

All RPS Trip Functions, with the exception of the Loss of Load and CHP trips, generate a pretrip alarm as the trip setpoint is approached.

The Allowable Values are specified for each safety related RPS trip Function which is credited in the safety analysis. Nominal trip setpoints are specified in the plant procedures. The nominal setpoints are selected to ensure plant parameters do not exceed the Allowable Value if the instrument loop is performing as required. The methodology used to determine the nominal trip setpoints is also provided in plant documents. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the analytical limit determined in the safety analysis in order to account for uncertainties appropriate to the trip Function. These uncertainties are addressed as described in plant documents. A channel is inoperable if its actual setpoint is not within its Allowable Value.

Setpoints in accordance with the Allowable Value will ensure that SLs of Chapter 2.0 are not violated during AOOs and the consequences of DBAs will be acceptable, providing the plant 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.

BASES

BACKGROUND (continued)

Reactor Protective System Bypasses

Three different types of trip bypass are utilized in the RPS, Operating Bypass, Zero Power Mode Bypass, and Trip Channel Bypass. The Operating Bypass or Zero Power Mode Bypass prevent the actuation of a trip unit or auxiliary trip unit; the Trip Channel Bypass prevents the trip unit output from affecting the Logic Matrix. A channel which is bypassed, other than as allowed by the Table 3.3.1-1 footnotes, cannot perform its specified safety function and must be considered to be inoperable.

Operating Bypasses

The Operating Bypasses are initiated and removed automatically during startup and shutdown as power level changes. An Operating Bypass prevents the associated RPS auxiliary trip unit from receiving a trip signal from the associated measurement channel. With the bypass in place, neither the pre-trip alarm nor the trip will actuate if the measured parameter exceeds the set point. An annunciator is provided for each Operating Bypass. The RPS trips with Operating Bypasses are:

a. High Startup Rate Trip bypass. The High Startup Rate trip is automatically bypassed when the associated wide range channel indicates below 1E-4% RTP, and when the associated power range excore channel indicates above 13% RTP. These bypasses are automatically removed between 1E-4% RTP and 13% RTP.

b. Loss of Load bypass. The Loss of Load trip is automatically bypassed when the associated power range excore channel indicates below 17% RTP. The bypass is automatically removed when the channel indicates above the set point. The same power range excore channel bistable is used to bypass the High Startup Rate trip and the Loss of Load trip for that RPS channel.

BASES

BACKGROUND

Operating Bypasses (continued)

Each wide range channel contains two bistables set at 1E-4% RTP, one bistable unit for each associated RPS channel. Each of the two wide range channels affect the Operating Bypasses for two RPS channels; wide range channel NI-1/3 for RPS channels A and C, wide range channel NI-2/4 for RPS channels B and D. Each of the four power range excore channel affects the Operating Bypasses for the associated RPS channel. The power range excore channel bistables associated with the Operating Bypasses are set at a nominal 15%, and are required to actuate between 13% RTP and 17% RTP.

Zero Power Mode (ZPM) Bypass

The ZPM Bypass is used when the plant is shut down and it is desired to raise the control rods for control rod drop testing with PCS flow, pressure or temperature too low for the RPS trips to be reset. ZPM bypasses may be manually initiated and removed when wide range power is below 1E-4% RTP, and are automatically removed if the associated wide range NI indicated power exceeds 1E-4% RTP. A ZPM bypass prevents the RPS trip unit from actuating if the measured parameter exceeds the set point. Operation of the pretrip alarm is unaffected by the zero power mode bypass. An annunciator indicates the presence of any ZPM bypass. The RPS trips with ZPM bypasses are:

a. Low Primary Coolant System Flow.

b. Low Steam Generator Pressure.

c. Thermal Margin/Low Pressure.

The wide range NI channels provide contact closure permissive signals when indicated power is below 1E-4% RTP. The ZPM bypasses may then be manually initiated or removed by actuation of key-lock switches. One key-lock switch located on each RPS cabinet controls the ZPM Bypass for the associated RPS trip channels. The bypass is automatically removed if the associated wide range NI indicated power exceeds 1E-4% RTP. The same wide range NI channel bistables that provide the ZPM Bypass permissive and removal signals also provide the high startup rate trip Operating Bypass actuation and removal.

BASES

BACKGROUND (continued)

Trip Channel Bypass

A Trip Channel Bypass is used when it is desired to physically remove an individual trip unit from the system, or when calibration or servicing of a trip channel could cause an inadvertent trip. A trip Channel Bypass may be manually initiated or removed at any time by actuation of a key-lock switch. A Trip Channel Bypass prevents the trip unit output from affecting the RPS logic matrix. A light above the bypass switch indicates that the trip channel has been bypassed. Each RPS trip unit has an associated trip channel bypass:

The key-lock trip channel bypass switch is located above each trip unit. The key cannot be removed when in the bypass position. Only one key for each trip parameter is provided, therefore the operator can bypass only one channel of a given parameter at a time. During the bypass condition, system logic changes from two-out-of-four to two-out-of-three channels required for trip.

APPLICABLE SAFETY ANALYSES

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis contained in Reference 4 takes credit for most RPS trip Functions. The High Startup Rate and Loss of Load Functions, which are not specifically credited in the accident analysis are part of the NRC approved licensing basis for the plant. The High Startup Rate and Loss of Load trips are purely equipment protective, and their use minimizes the potential for equipment damage.

The specific safety analyses applicable to each protective Function are identified below.

1. Variable High Power Trip (VHPT)

   The VHPT provides reactor core protection against positive reactivity excursions.

   The safety analysis assumes that this trip is OPERABLE to terminate excessive positive reactivity insertions during power operation and while shut down.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

2. High Startup Rate Trip

There are no safety analyses which take credit for functioning of the High Startup Rate Trip. The High Startup Rate trip is used to trip the reactor when excore wide range power indicates an excessive rate of change. The High Startup Rate trip minimizes transients for events such as a continuous control rod withdrawal or a boron dilution event from low power levels. The trip may be operationally bypassed when THERMAL POWER is < 1E-4% RTP, when poor counting statistics may lead to erroneous indication. It may also be operationally bypassed at > 13% RTP, where moderator temperature coefficient and fuel temperature coefficient make high rate of change of power unlikely.

There are only two wide range drawers, with each supplying contact input to auxiliary trip units in two RPS channels.

3. Low Primary Coolant System Flow Trip

The Low PCS Flow trip provides DNB protection during events which suddenly reduce the PCS flow rate during power operation, such as loss of power to, or seizure of, a primary coolant pump.

Flow in each of the four PCS loops is determined from pressure drop from inlet to outlet of the SGs. The total PCS flow is determined, for the RPS flow channels, by summing the loop pressure drops across the SGs and correlating this pressure sum with the sum of SG differential pressures which exist at 100% flow (four pump operation at full power T_{ave}). Full PCS flow is that flow which exists at RTP, at full power T_{ave}, with four pumps operating.

4, 5. Low Steam Generator Level Trip

The Low Steam Generator Level trips are provided to trip the reactor in the event of excessive steam demand (to prevent overcooling the PCS) and loss of feedwater events (to prevent overpressurization of the PCS).

The Allowable Value assures that there will be sufficient water inventory in the SG at the time of trip to allow a safe and orderly plant shutdown and to prevent SG dryout assuming minimum AFW capacity.

BASES

APPLICABLE SAFETY ANALYSIS

4, 5. Low Steam Generator Level Trip (continued)

Each SG level is sensed by measuring the differential pressure in the upper portion of the downcomer annulus in the SG. These trips share four level sensing channels on each SG with the AFW actuation signal.

6, 7. Low Steam Generator Pressure Trip

The Low Steam Generator Pressure trip provides protection against an excessive rate of heat extraction from the steam generators, which would result in a rapid uncontrolled cooldown of the PCS. This trip provides a mitigation function in the event of an MSLB.

The Low SG Pressure channels are shared with the Low SG Pressure signals which isolate the steam and feedwater lines.

8. High Pressurizer Pressure Trip

The High Pressurizer Pressure trip, in conjunction with pressurizer safety valves and Main Steam Safety Valves (MSSVs), provides protection against overpressure conditions in the PCS when at operating temperature. The safety analyses assume the High Pressurizer Pressure trip is OPERABLE during accidents and transients which suddenly reduce PCS cooling (e.g., Loss of Load, Main Steam Isolation Valve (MSIV) closure, etc.) or which suddenly increase reactor power (e.g., rod ejection accident).

The High Pressurizer Pressure trip shares four safety grade instrument channels with the TM/LP trip, Anticipated Transient Without Scram (ATWS) and PORV circuits, and the Pressurizer Low Pressure Safety Injection Signal.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

9. Thermal Margin/Low Pressure (TM/LP) Trip

The TM/LP trip is provided to prevent reactor operation when the DNBR is insufficient. The TM/LP trip protects against slow reactivity or temperature increases, and against pressure decreases.

The trip is initiated whenever the PCS pressure signal drops below a minimum value (P_{min}) or a computed value (P_{var}) as described below, whichever is higher.

The TM/LP trip uses Q Power, ASI, pressurizer pressure, and cold leg temperature (T_c) as inputs.

Q Power is the higher of core THERMAL POWER (ΔT Power) or nuclear power. The ΔT power uses hot leg and cold leg RTDs as inputs. Nuclear power uses the power range excore channels as inputs. Both the ΔT and excore power signals have provisions for calibration by calorimetric calculations.

The ASI is calculated from the upper and lower power range excore detector signals, as explained in Section 1.1, "Definitions." The signal is corrected for the difference between the flux at the core periphery and the flux at the detectors.

The T_c value is the higher of the two cold leg signals.

The Low Pressurizer Pressure trip limit (P_{var})is calculated using the equations given in Table 3.3.1-2.

The calculated limit (P_{var}) is then compared to a fixed Low Pressurizer Pressure trip limit (P_{min}). The auctioneered highest of these signals becomes the trip limit (P_{trip}). P_{trip} is compared to the measured PCS pressure and a trip signal is generated when the measured pressure for that channel is less than or equal to P_{trip}. A pre-trip alarm is also generated when P is less than or equal to the pre-trip setting, $P_{trip} + \Delta P$.

The TM/LP trip setpoint is a complex function of these inputs and represents a minimum acceptable PCS pressure for the existing temperature and power conditions. It is compared to actual PCS pressure in the TM/LP trip unit.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

10. Loss of Load Trip

There are no safety analyses which take credit for functioning of the Loss of Load Trip.

The Loss of Load trip is provided to prevent lifting the pressurizer and main steam safety valves in the event of a turbine generator trip while at power. The trip is equipment protective. The safety analyses do not assume that this trip functions during any accident or transient. The Loss of Load trip uses a single pressure switch in the turbine auto stop oil circuit to sense a turbine trip for input to all four RPS auxiliary trip units.

11. Containment High Pressure Trip

The Containment High Pressure trip provides a reactor trip in the event of a Loss of Coolant Accident (LOCA) or Main Steam Line Break (MSLB). The Containment High Pressure trip shares sensors with the Containment High Pressure sensing logic for Safety Injection, Containment Isolation, and Containment Spray. Each of these sensors has a single bellows which actuates two microswitches. One microswitch on each of four sensors provides an input to the RPS.

12. Zero Power Mode Bypass Removal

The only RPS bypass considered in the safety analyses is the Zero Power Mode (ZPM) Bypass. The ZPM Bypass is used when the plant is shut down and it is desired to raise the control rods for control rod drop testing with PCS flow or temperature too low for the RPS Low PCS Flow, Low SG Pressure, or Thermal Margin/Low Pressure trips to be reset. ZPM bypasses are automatically removed if the wide range NI indicated power exceeds 1E-4% RTP.

BASES

APPLICABLE SAFETY ANALYSIS

12. Zero Power Mode Bypass Removal (continued)

The safety analyses take credit for automatic removal of the ZPM Bypass if reactor criticality due to a Continuous Control Rod Bank Withdrawal should occur with the affected trips bypassed and PCS flow, pressure, or temperature below the values at which the RPS could be reset. The ZPM Bypass would effectively be removed when the first wide range NI channel indication reached 1E-4% RTP. With the ZPM Bypass for two RPS channels removed, the RPS would trip on one of the un-bypassed trips. This would prevent the reactor reaching an excessive power level.

If a reactor criticality due to a Continuous Control Rod Bank Withdrawal should occur when PCS flow, steam generator pressure, and PCS pressure (TM/LP) were above their trip setpoints, a trip would terminate the event when power increased to the minimum setting (nominally 30%) of the Variable High Power Trip. In this case, the monitored parameters are at or near their normal operational values, and a trip initiated at 30% RTP provides adequate protection.

The RPS design also includes automatic removal of the Operating Bypasses for the High Startup Rate and Loss of Load trips. The safety analyses do not assume functioning of either these trips or the automatic removal of their bypasses.

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

LCO

The LCO requires all instrumentation performing an RPS Function to be OPERABLE. Failure of the trip unit (including its output relays), any required portion of the associated instrument channel, or both, renders the affected channel(s) inoperable and reduces the reliability of the affected Functions. Failure of an automatic ZPM bypass removal channel may also impact the associated instrument channel(s) and reduce the reliability of the affected Functions.

BASES

LCO (continued)

Actions allow Trip Channel Bypass of individual channels, but the bypassed channel must be considered to be inoperable. The bypass key used to bypass a single channel cannot be simultaneously used to bypass that same parameter in other channels. This interlock prevents operation with more than one channel of the same Function trip channel bypassed. The plant is normally restricted to 7 days in a trip channel bypass, or otherwise inoperable condition before either restoring the Function to four channel operation (two-out-of-four logic) or placing the channel in trip (one-out-of-three logic).

The Allowable Values are specified for each safety related RPS trip Function which is credited in the safety analysis. Nominal trip setpoints are specified in the plant procedures. The nominal setpoints are selected to ensure plant parameters do not exceed the Allowable Value if the instrument loop is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the analytical limit determined in the safety analysis in order to account for uncertainties appropriate to the trip Function. These uncertainties are addressed as described in plant documents. Neither Allowable Values nor setpoints are specified for the non-safety related RPS Trip Functions, since no safety analysis assumptions would be violated if they are not set at a particular value.

The following Bases for each trip Function identify the above RPS trip Function criteria items that are applicable to establish the trip Function OPERABILITY.

1. Variable High Power Trip (VHPT)

This LCO requires all four channels of the VHPT Function to be OPERABLE.

The Allowable Value is high enough to provide an operating envelope that prevents unnecessary VHPT trips during normal plant operations. The Allowable Value is low enough for the system to function adequately during reactivity addition events.

BASES

LCO

1. Variable High Power Trip (VHPT) (continued)

The VHPT is designed to limit maximum reactor power to its maximum design and to terminate power excursions initiating at lower powers without power reaching this full power limit. During plant startup, the VHPT trip setpoint is initially at its minimum value, ≤ 30%. Below 30% RTP, the VHPT setpoint is not required to "track" with Q Power, i.e., be adjusted to within 15% RTP. It remains fixed until manually reset, at which point it increases to ≤ 15% above existing Q Power.

The maximum allowable setting of the VHPT is 106.5% RTP. Adding to this the possible variation in trip setpoint due to calibration and instrument error, the maximum actual steady state power at which a trip would be actuated is 115%, which is the value assumed in the safety analysis.

2. High Startup Rate Trip

This LCO requires four channels of High Startup Rate Trip Function to be OPERABLE in MODES 1 and 2.

The High Startup Rate trip serves as a backup to the administratively enforced startup rate limit. The Function is not credited in the accident analyses; therefore, no Allowable Value for the trip or operating bypass Functions is derived from analytical limits and none is specified.

The four channels of the High Startup Rate trip are derived from two wide range NI signal processing drawers. Thus, a failure in one wide range channel could render two RPS channels inoperable. It is acceptable to continue operation in this condition because the High Startup Rate trip is not credited in any safety analyses.

The requirement for this trip Function is modified by a footnote, which allows the High Startup Rate trip to be bypassed when the wide range NI indicates below 10E-4% or when THERMAL POWER is above 13% RTP. If a High Startup Rate trip is bypassed when power is between these limits, it must be considered to be inoperable.

BASES

LCO (continued)

3. Low Primary Coolant System Flow Trip

This LCO requires four channels of Low PCS Flow Trip Function to be OPERABLE.

This trip is set high enough to maintain fuel integrity during a loss of flow condition. The setting is low enough to allow for normal operating fluctuations from offsite power.

The Low PCS Flow trip setpoint of 95% of full PCS flow insures that the reactor cannot operate when the flow rate is less than 93% of the nominal value considering instrument errors. Full PCS flow is that flow which exists at RTP, at full power T_{ave}, with four pumps operating.

The requirement for this trip Function is modified by a footnote, which allows use of the ZPM bypass when wide range power is below 1E-4% RTP. That bypass is automatically removed when the associated wide range channel indicates 1E-4% RTP. If a trip channel is bypassed when power is above 1E-4% RTP, it must be considered to be inoperable.

4, 5. Low Steam Generator Level Trip

This LCO requires four channels of Low Steam Generator Level Trip Function per steam generator to be OPERABLE.

The 25.9% Allowable Value assures that there is an adequate water inventory in the steam generators when the reactor is critical and is based upon narrow range instrumentation. The 25.9% indicated level corresponds to the location of the feed ring.

BASES

LCO (continued)

6, 7. Low Steam Generator Pressure Trip

This LCO requires four channels of Low Steam Generator Pressure Trip Function per steam generator to be OPERABLE.

The Allowable Value of 500 psia is sufficiently below the full load operating value for steam pressure so as not to interfere with normal plant operation, but still high enough to provide the required protection in the event of excessive steam demand. Since excessive steam demand causes the PCS to cool down, resulting in positive reactivity addition to the core, a reactor trip is required to offset that effect.

The requirement for this trip Function is modified by a footnote, which allows use of the ZPM bypass when wide range power is below 1E-4% RTP. That bypass is automatically removed when the associated wide range channel indicates 1E-4% RTP. If a trip channel is bypassed when power is above 1E-4% RTP, it must be considered to be inoperable.

8. High Pressurizer Pressure Trip

This LCO requires four channels of High Pressurizer Pressure Trip Function to be OPERABLE.

The Allowable Value is set high enough to allow for pressure increases in the PCS during normal operation (i.e., plant transients) not indicative of an abnormal condition. The setting is below the lift setpoint of the pressurizer safety valves and low enough to initiate a reactor trip when an abnormal condition is indicated.

9. Thermal Margin/Low Pressure (TM/LP) Trip

This LCO requires four channels of TM/LP Trip Function to be OPERABLE.

The TM/LP trip setpoints are derived from the core thermal limits through application of appropriate allowances for measurement uncertainties and processing errors. The allowances specifically account for instrument drift in both power and inlet temperatures, calorimetric power measurement, inlet temperature measurement, and primary system pressure measurement.

BASES

LCO

9. Thermal Margin/Low Pressure (TM/LP) Trip (continued)

Other uncertainties including allowances for assembly power tilt, fuel pellet manufacturing tolerances, core flow measurement uncertainty and core bypass flow, inlet temperature measurement time delays, and ASI measurement, are included in the development of the TM/LP trip setpoint used in the accident analysis.

The requirement for this trip Function is modified by a footnote, which allows use of the ZPM bypass when wide range power is below 1E-4% RTP. That bypass is automatically removed when the associated wide range channel indicates 1E-4% RTP. If a trip channel is bypassed when power is above 1E-4% RTP, it must be considered to be inoperable.

10. Loss of Load Trip

The LCO requires four Loss of Load Trip Function channels to be OPERABLE in MODE 1 with THERMAL POWER ≥ 17% RTP.

The Loss of Load trip may be bypassed or be inoperable with THERMAL POWER < 17% RTP, since it is no longer needed to prevent lifting of the pressurizer safety valves or steam generator safety valves in the event of a Loss of Load. Loss of Load Trip unit must be considered inoperable if it is bypassed when THERMAL POWER is above 17% RTP.

This LCO requires four RPS Loss of Load auxiliary trip units, relays 305L and 305R, and pressure switch 63/AST-2 to be OPERABLE. With those components OPERABLE, a turbine trip will generate a reactor trip. The LCO does not require the various turbine trips, themselves, to be OPERABLE.

The Nuclear Steam Supply System and Steam Dump System are capable of accommodating the Loss of Load without requiring the use of the above equipment.

The Loss of Load Trip Function is not credited in the accident analysis; therefore, an Allowable Value for the trip cannot be derived from analytical limits, and is not specified.

BASES

LCO (continued)

11. Containment High Pressure Trip

This LCO requires four channels of Containment High Pressure Trip Function to be OPERABLE.

The Allowable Value is high enough to allow for small pressure increases in containment expected during normal operation (i.e., plant heatup) that are not indicative of an abnormal condition. The setting is low enough to initiate a reactor trip to prevent containment pressure from exceeding design pressure following a DBA and ensures the reactor is shutdown before initiation of safety injection and containment spray.

12. ZPM Bypass

The LCO requires that four channels of automatic Zero Power Mode (ZPM) Bypass removal instrumentation be OPERABLE. Each channel of automatic ZPM Bypass removal includes a shared wide range NI channel, an actuating bistable in the wide range drawer, and a relay in the associated RPS cabinet. Wide Range NI channel 1/3 is shared between ZPM Bypass removal channels A and C; Wide Range NI channel 2/4, between ZPM Bypass removal channels B and D. An operable bypass removal channel must be capable of automatically removing the capability to bypass the affected RPS trip channels with the ZPM Bypass key switch at the proper setpoint.

APPLICABILITY

This LCO requires all safety related trip functions to be OPERABLE in accordance with Table 3.3.1-1.

Those RPS trip Functions which are assumed in the safety analyses (all except High Startup Rate and Loss of Load), are required to be operable in MODES 1 and 2, and in MODES 3, 4, and 5 with more than one full-length control rod capable of being withdrawn and PCS boron concentration less than REFUELING BORON CONCENTRATION.

BASES

APPLICABILITY (continued)

These trip Functions are not required while in MODES 3, 4, or 5, if PCS boron concentration is at REFUELING BORON CONCENTRATION, or when no more than one full-length control rod is capable of being withdrawn, because the RPS Function is already fulfilled. REFUELING BORON CONCENTRATION provides sufficient negative reactivity to assure the reactor remains subcritical regardless of control rod position, and the safety analyses assume that the highest worth withdrawn full-length control rod will fail to insert on a trip. Therefore, under these conditions, the safety analyses assumptions will be met without the RPS trip Function.

The High Startup Rate Trip Function is required to be OPERABLE in MODES 1 and 2, but may be bypassed when the associated wide range NI channel indicates below 1E-4% power, when poor counting statistics may lead to erroneous indication. In MODES 3, 4, 5, and 6, the High Startup Rate trip is not required to be OPERABLE. Wide range channels are required to be OPERABLE in MODES 3, 4, and 5, by LCO 3.3.9, "Neutron Flux Monitoring Channels," and in MODE 6, by LCO 3.9.2, "Nuclear Instrumentation."

The Loss of Load trip is required to be OPERABLE with THERMAL POWER at or above 17% RTP. Below 17% RTP, the ADVs are capable of relieving the pressure due to a Loss of Load event without challenging other overpressure protection.

The trips are designed to take the reactor subcritical, maintaining the SLs during AOOs and assisting the ESF in providing acceptable consequences during accidents.

ACTIONS

The most common causes of channel inoperability are outright failure of loop components or drift of those loop components which is sufficient to exceed the tolerance provided in the plant setpoint analysis. Loop component failures are typically identified by the actuation of alarms due to the channel failing to the "safe" condition, during CHANNEL CHECKS (when the instrument is compared to the redundant channels), or during the CHANNEL FUNCTIONAL TEST (when an automatic component might not respond properly). Typically, the drift of the loop components is found to be small and results in a delay of actuation rather than a total loss of function. Excessive loop component drift would, most likely, be identified during a CHANNEL CHECK (when the instrument is compared to the redundant channels) or during a CHANNEL CALIBRATION (when instrument loop components are checked against reference standards).

BASES

ACTIONS (continued)

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 RPS bistable trip unit is found inoperable, all affected Functions provided by that channel must be declared inoperable, and the plant must enter the Condition for the particular protection Functions affected.

When the number of inoperable channels in a trip Function exceeds that specified in any related Condition associated with the same trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 is immediately entered if applicable in the current MODE of operation.

A Note has been added to the ACTIONS to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each Function. The Completion Times of each inoperable Function will be tracked separately for each Function, starting from the time the Condition was entered.

A.1

Condition A applies to the failure of a single channel in any required RPS Function, except High Startup Rate, Loss of Load, or ZPM Bypass Removal. (Condition A is modified by a Note stating that this Condition does not apply to the High Startup Rate, Loss of Load, or ZPM Bypass Removal Functions. The failure of one channel of those Functions is addressed by Conditions B, C, or D.)

If one RPS bistable trip unit or associated instrument channel is inoperable, operation is allowed to continue. Since the trip unit and associated instrument channel combine to perform the trip function, this Condition is also appropriate if both the trip unit and the associated instrument channel are inoperable. Though not required, the inoperable channel may be bypassed. The provision of four trip channels allows one channel to be bypassed (removed from service) during operations, placing the RPS in two-out-of-three coincidence logic. The failed channel must be restored to OPERABLE status or placed in trip within 7 days.

Required Action A.1 places the Function in a one-out-of-three configuration. In this configuration, common cause failure of dependent channels cannot prevent trip.

BASES

ACTIONS

A.1 (continued)

The Completion Time of 7 days is based on operating experience, which has demonstrated that a random failure of a second channel occurring during the 7 day period is a low probability event.

B.1

Condition B applies to the failure of a single High Startup Rate trip unit or associated instrument channel.

If one trip unit or associated instrument channel fails, it must be restored to OPERABLE status prior to entering MODE 2 from MODE 3. A shutdown provides the appropriate opportunity to repair the trip function and conduct the necessary testing. The Completion Time is based on the fact that the safety analyses take no credit for the functioning of this trip.

C.1

Condition C applies to the failure of a single Loss of Load or associated instrument channel.

If one trip unit or associated instrument channel fails, it must be restored to OPERABLE status prior to THERMAL POWER ≥ 17% RTP following a shutdown. If the plant is shutdown at the time the channel becomes inoperable, then the failed channel must be restored to OPERABLE status prior to THERMAL POWER ≥ 17% RTP. For this Completion Time, "following a shutdown" means this Required Action does not have to be completed until prior to THERMAL POWER ≥ 17% RTP for the first time after the plant has been in MODE 3 following entry into the Condition. The Completion Time trip assures that the plant will not be restarted with an inoperable Loss of Load trip channel.

BASES

ACTIONS (continued)

D.1 and D.2

Condition D applies when one or more automatic ZPM Bypass removal channels are inoperable. If the ZPM Bypass removal channel cannot be restored to OPERABLE status, the affected ZPM Bypasses must be immediately removed, or the bypassed RPS trip Function channels must be immediately declared to be inoperable. Unless additional circuit failures exist, the ZPM Bypass may be removed by placing the associated "Zero Power Mode Bypass" key operated switch in the normal position.

A trip channel which is actually bypassed, other than as allowed by the Table 3.3.1-1 footnotes, cannot perform its specified safety function and must immediately be declared to be inoperable.

E.1 and E.2

Condition E applies to the failure of two channels in any RPS Function, except ZPM Bypass Removal Function. (The failure of ZPM Bypass Removal Functions is addressed by Condition D.).

Condition E is modified by a Note stating that this Condition does not apply to the ZPM Bypass Removal Function.

The Required Actions are modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODES even though two channels are inoperable, with one channel tripped. MODE changes in this configuration are allowed because two trip channels for the affected function remain OPERABLE. A trip occurring in either or both of those channels would cause a reactor trip.

In this configuration, the protection system is in a one-out-of-two logic, and the probability of a common cause failure affecting both of the OPERABLE channels during the 7 days permitted is remote.

Required Action E.1 provides for placing one inoperable channel in trip within the Completion Time of 1 hour. Though not required, the other inoperable channel may be (trip channel) bypassed.

BASES

ACTIONS

E.1 and E.2 (continued)

This Completion Time is sufficient to allow the operator to take all appropriate actions for the failed channels while ensuring that the risk involved in operating with the failed channels is acceptable. With one channel of protective instrumentation bypassed or inoperable in an untripped condition, the RPS is in a two-out-of-three logic for that function; but with another channel failed, the RPS may be operating in a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, one of the inoperable channels is placed in trip. This places the RPS in a one-out-of-two for that function logic. If any of the other unbypassed channels for that function receives a trip signal, the reactor will trip.

Action E.2 is modified by a Note stating that this Action does not apply to (is not required for) the High Startup Rate and Loss of Load Functions.

One channel is required to be restored to OPERABLE status within 7 days for reasons similar to those stated under Condition A. After one channel is restored to OPERABLE status, the provisions of Condition A still apply to the remaining inoperable channel. Therefore, the channel that is still inoperable after completion of Required Action E.2 must be placed in trip if more than 7 days have elapsed since the initial channel failure.

F.1

The power range excore channels are used to generate the internal ASI signal used as an input to the TM/LP trip. They also provide input to the Thermal Margin Monitors for determination of the Q Power input for the TM/LP trip and the VHPT. If two power range excore channels cannot be restored to OPERABLE status, power is restricted or reduced during subsequent operations because of increased uncertainty associated with inoperable power range excore channels which provide input to those trips.

The Completion Time of 2 hours is adequate to reduce power in an orderly manner without challenging plant systems.

BASES

ACTIONS (continued)

G.1, G.2.1, and G.2.2

Condition G is entered when the Required Action and associated Completion Time of Condition A, B, C, D, E, or F are not met, or if the control room ambient air temperature exceeds 90°F.

If the control room ambient air temperature exceeds 90°F, all Thermal Margin Monitor channels are rendered inoperable because their environmental qualification temperature limit is exceeded. In this condition, or if the Required Actions and associated Completion Times are not met, the reactor must be placed in a condition in which the LCO does not apply. To accomplish this, the plant must be placed in MODE 3, with no more than one full-length control rod capable of being withdrawn or with the PCS boron concentration at REFUELING BORON CONCENTRATION in 6 hours.

The Completion Time is reasonable, based on operating experience, for placing the plant in MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The Completion Time is also reasonable to ensure that no more than one full-length control rod is capable of being withdrawn or that the PCS boron concentration is at REFUELING BORON CONCENTRATION.

SURVEILLANCE REQUIREMENTS

The SRs for any particular RPS Function are found in the SR column of Table 3.3.1-1 for that Function. Most Functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION.

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours 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. Under most conditions, 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

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

The Containment High Pressure and Loss of Load channels are pressure switch actuated. As such, they have no associated control room indicator and do not require a CHANNEL CHECK.

The Frequency, about once every shift, is based on operating experience that demonstrates the rarity of channel failure. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

This SR verifies that the control room ambient air temperature is within the environmental qualification temperature limits for the most restrictive RPS components, which are the Thermal Margin Monitors. These monitors provide input to both the VHPT Function and the TM/LP Trip Function. The 12 hour Frequency is reasonable based on engineering judgement and plant operating experience.

SR 3.3.1.3

A daily calibration (heat balance) is performed when THERMAL POWER is ≥ 15%. The daily calibration consists of adjusting the "nuclear power calibrate" potentiometers to agree with the calorimetric calculation if the absolute difference is ≥ 1.5%. Nuclear power is adjusted via a potentiometer, or THERMAL POWER is adjusted via a Thermal Margin Monitor bias number, as necessary, in accordance with the daily calibration (heat balance) procedure. Performance of the daily calibration ensures that the two inputs to the Q power measurement are indicating accurately with respect to the much more accurate secondary calorimetric calculation.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

The Frequency of 24 hours is based on plant operating experience and takes into account indications and alarms located in the control room to detect deviations in channel outputs.

The Frequency is modified by a Note indicating this Surveillance must be performed within 12 hours after THERMAL POWER is ≥ 15% RTP. The secondary calorimetric is inaccurate at lower power levels. The 12 hours allows time requirements for plant stabilization, data taking, and instrument calibration.

SR 3.3.1.4

It is necessary to calibrate the power range excore channel upper and lower subchannel amplifiers such that the measured ASI reflects the true core power distribution as determined by the incore detectors. ASI is utilized as an input to the TM/LP trip function where it is used to ensure that the measured axial power profiles are bounded by the axial power profiles used in the development of the T_{inlet} limitation of LCO 3.4.1. An adjustment of the excore channel is necessary only if individual excore channel ASI differs from AXIAL OFFSET, as measured by the incores, by greater than 0.02.

A Note indicates the Surveillance is not required to have been performed until 12 hours after THERMAL POWER is ≥ 25% RTP. Uncertainties in the excore and incore measurement process make it impractical to calibrate when THERMAL POWER is < 25% RTP. The 12 hours allows time for plant stabilization, data taking, and instrument calibration.

The 31 day Frequency is adequate, based on operating experience of the excore linear amplifiers and the slow burnup of the detectors. The excore readings are a strong function of the power produced in the peripheral fuel bundles and do not represent an integrated reading across the core. Slow changes in neutron flux during the fuel cycle can also be detected at this Frequency.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.5

A CHANNEL FUNCTIONAL TEST is performed on each RPS instrument channel, except Loss of Load and High Startup Rate, every 92 days to ensure the entire channel will perform its intended function when needed. For the TM/LP Function, the constants associated with the Thermal Margin Monitors must be verified to be within tolerances.

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

Any setpoint adjustment must be consistent with the assumptions of the current setpoint analysis.

The Frequency of 92 days is based on the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Ref. 5).

SR 3.3.1.6

A calibration check of the power range excore channels using the internal test circuitry is required every 92 days. This SR uses an internally generated test signal to check that the 0% and 50% levels read within limits for both the upper and lower detector, both on the analog meter and on the TMM screen. This check verifies that neither the zero point nor the amplifier gain adjustment have undergone excessive drift since the previous complete CHANNEL CALIBRATION.

The Frequency of 92 days is acceptable, based on plant operating experience, and takes into account indications and alarms available to the operator in the control room.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.7

A CHANNEL FUNCTIONAL TEST on the Loss of Load and High Startup Rate channels is performed prior to a reactor startup to ensure the entire channel will perform its intended function.

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

The High Startup Rate trip is actuated by either of the Wide Range Nuclear Instrument Startup Rate channels. NI-1/3 sends a trip signal to RPS channels A and C; NI-2/4 to channels B and D. Since each High Startup Rate channel would cause a trip on two RPS channels, the High Startup Rate trip is not tested when the reactor is critical.

The four Loss of Load Trip channels are all actuated by a single pressure switch monitoring turbine auto stop oil pressure which is not tested when the reactor is critical. Operating experience has shown that these components usually pass the Surveillance when performed at a Frequency of once per 7 days prior to each reactor startup.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a CHANNEL CALIBRATION every 18 months.

CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor (except neutron detectors). The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be consistent with the setpoint analysis.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

The bistable setpoints must be found to trip within the Allowable Values specified in the LCO and left set consistent with the assumptions of the setpoint analysis. The Variable High Power Trip setpoint shall be verified to reset properly at several indicated power levels during (simulated) power increases and power decreases.

The as-found and as-left values must also be recorded and reviewed for consistency with the assumptions of the setpoint analysis.

As part of the CHANNEL CALIBRATION of the wide range Nuclear Instrumentation, automatic removal of the ZPM Bypass for the Low PCS Flow, TM/LP must be verified to assure that these trips are available when required.

The Frequency is based upon the assumption of an 18 month calibration interval for the determination of the magnitude of equipment drift.

This SR is modified by a Note which states that it is not necessary to calibrate neutron detectors because they are passive devices with minimal drift and because of the difficulty of simulating a meaningful signal. Slow changes in power range excore neutron detector sensitivity are compensated for by performing the daily calorimetric calibration (SR 3.3.1.3) and the monthly calibration using the incore detectors (SR 3.3.1.4). Sudden changes in detector performance would be noted during the required CHANNEL CHECKS (SR 3.3.1.1).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 21
2. 10 CFR 100
3. IEEE Standard 279-1971, April 5, 1972
4. FSAR, Chapter 14
5. CEN-327, June 2, 1986, including Supplement 1, March 3, 1989

Table B 3.3.1-1 (page 1 of 1)
Instruments Affecting Multiple Specifications

REQUIRED INSTRUMENT CHANNELS	AFFECTED SPECIFICATIONS
Source Range NI-1/3 & 2/4, Count Rate Signal 3.3.9	
	3.9.2
Source Range NI-1/3, Count Rate Indication @ C-150 Panel	3.3.8 #1
Wide Range NI-1/3 & 2/4, Flux Level 10^{-4} Bypass 3.3.1 #3,6,7,9,&12	
Wide Range NI-1/3 & 2/4, Startup Rate	3.3.1 #2
Wide Range NI-1/3 & 2/4, Flux Level Indication 3.3.7 #3	
	3.3.9
Power Range NI-5, 6, 7 & 8, Tq	3.2.1
	3.2.3
Power Range NI-5, 6, 7 & 8, Q Power	3.3.1 #1 & 9
Power Range NI-5, 6, 7 & 8, ASI	3.3.1 #9
	3.2.1
	3.2.4
Power Range NI-5, 6, 7 & 8, Loss of Load/High Startup Rate Bypass	3.3.1 #2 & 10
PCS TC TT-0112 & 0122 CC & CD, Temperature Signal (SMM)	3.3.7 #5
PCS TC TT-0112 & 0122 CA, CB, CC & CD, Temperature Signal (Q Power & TMM)	3.3.1 #1 & 9
	3.4.1.b
PCS TC TT-0112CA & 0122CB, Temperature Signal (LTOP)	3.4.12.b.1
PCS TC TT-0112CC & 0122CD (PTR-0112 & 0122) Temperature Indication	3.3.7 #2
PCS TC TT-0112CA, Temperature Signal (SPI ΔT Power for PDIL Alarm Circuit)	3.1.6
PCS TC TT-0122CB, Temperature Signal (PIP ΔT Power for PDIL Alarm Circuit)	3.1.6
PCS TH TT-0112 & 0122 HC & HD, Temperature Signal (SMM)	3.3.7 #5
PCS TH TT-0112HC & 0122HD (PTR-0112 & 0122) Temperature Indication	3.3.7 #1
PCS TH TT-0112 & 0122 HA, HB, HC & HD, Temperature Signal (Q Power)	3.3.1 #1 & 9
PCS TH TT-0112HA, Temperature Signal (SPI ΔT Power for PDIL Alarm Circuit)	3.1.6
PCS TH TT-0122HB, Temperature Signal (PIP ΔT Power for PDIL Alarm Circuit)	3.1.6
Thermal Margin Monitor PY-0102A, B, C, & D	3.3.1 #1 & 9
Pressurizer Pressure PT-0105A & B, Pressure Signal (WR Indication & LTOP)	3.3.7 #5
	3.3.4.12.b.1
Pressurizer Pressure PT-0102A, B, C & D, Pressure Signal (RPS & SIS)	3.3.1 #8 & 9
	3.3.3 #1.a
Pressurizer Pressure PT-0104A & B, Pressure Signal (LTOP & SDC Interlock)	3.4.12.b.1
	3.4.14
Pressurizer Pressure PI-0110, Pressure Indication @ C-150 Panel	3.3.8 #2
SG Level LT-0751 & 0752 A, B, C & D, Level Signal (RPS & AFAS)	3.3.1 #4 & 5
	3.3.3 #6.a & 6.b
SG Level LI-0757C & 0758C, Wide Range Level Indication @ C-150 Panel	3.3.8 #10 & 11
SG Level LI-0757 & 0758 A & B, Wide Range Level Indication	3.3.7 #11 & 12
SG Pressure PT-0751 & 0752 A, B, C&D, Pressure Signal (RPS & SG Isolation)	3.3.1 #6 & 7
	3.3.3 #4.a & 4.b
SG Pressure PIC-0751 & 0752 A, B, C & D, Pressure Indication	3.3.7 #13 & 14
SG Pressure PI-0751E & 0752E, Pressure Indication @ C-150 Panel	3.3.8 #8 & 9
Containment Pressure PS-1801, 1802, 1803&1804, Switch Output (RPS)	3.3.1 #11
Containment Pressure PS-1801, 1802A, 1803 & 1804A, Switch Output (ESF Actuation)	3.3.3 #2.a
Containment Pressure PS-1801A, 1802, 1803A & 1804, Switch Output (ESF Actuation)	3.3.3 #2.b

Note: The information provided in this table is intended for use as an aid to distinguish those instrument channels which provide more than one required function and to describe which specifications they affect. The information in this table should not be taken as inclusive for all instruments nor affected specifications.

B 3.3 INSTRUMENTATION

B 3.3.2 Reactor Protective System (RPS) Logic and Trip Initiation

BASES

BACKGROUND

The RPS initiates a reactor trip to protect against violating the acceptable fuel design limits and reactor coolant pressure boundary integrity during Anticipated Operational Occurrences (AOOs). By tripping the reactor, the RPS also assists the Engineered Safety Features (ESF) systems in mitigating accidents.

The protection and monitoring systems have been designed to ensure safe operation of the reactor. This is achieved by specifying Limiting Safety System Settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters and equipment performance.

The LSSS, defined in this Specification as the Allowable Value, 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 one or more times during the plant life, the acceptable limits are:

- The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling;
- Fuel centerline melting shall not occur; and
- The Primary Coolant System (PCS) pressure SL of 2750 psia shall not be exceeded.

Maintaining the parameters within the above values ensures that the offsite dose will be within the 10 CFR 50 (Ref. 1) and 10 CFR 100 (Ref. 2) criteria during AOOs.

BASES

BACKGROUND (continued)

Accidents are events that are analyzed even though they are not expected to occur during the plant life. The acceptable limit during accidents is that the offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 (Ref. 2) limits. Different accident categories allow a different fraction of these limits based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RPS is segmented into four interconnected modules. These modules are:

- Measurement channels (or pressure switches);
- Bistable trip units;
- Matrix Logic; and
- Trip Initiation Logic.

This LCO addresses the RPS Logic (Matrix Logic and Trip Initiation Logic), including Manual Trip capability. LCO 3.3.1, "Reactor Protective System (RPS) Instrumentation," provides a description of the role of the measurement channels and associated bistable trip units in the RPS. The RPS Logic is summarized below:

RPS Logic

The RPS Logic, consisting of Matrix Logic and Trip Initiation Logic, employs a scheme that provides a reactor trip when trip units in any two of the four channels sense the same input parameter trip. This is called a two-out-of-four trip logic. This logic and the clutch power supply configuration are shown in FSAR Figure 7-1 (Ref. 3).

Bistable trip unit relay contact outputs from the four channels are configured into six logic matrices. Each logic matrix checks for a coincident trip in the same parameter in two trip unit channels. The matrices are designated the AB, AC, AD, BC, BD, and CD matrices to reflect the bistable trip unit channels being monitored. Each logic matrix contains four normally energized matrix relays. When a coincidence is detected, consisting of a trip in the same Function in the two channels being monitored by the logic matrix, all four matrix relay coils de-energize.

BASES

BACKGROUND

RPS Logic (continued)

The matrix relay contacts are arranged into trip paths, with one of the four matrix relays in each matrix opening contacts in one of the four trip paths. Each trip path provides power to one of the four normally energized clutch power supply "M-contactors" (M1, M2, M3, and M4). The trip paths thus each have six contacts in series, one from each matrix, and perform a logical OR function, de-energizing the M-contactors if any one or more of the six logic matrices indicate a coincidence condition.

When a coincidence occurs in two RPS channels, all four matrix relays in the affected matrix de-energize. This in turn de-energizes all four M-contactors, which interrupt AC input power to the four clutch power supplies, allowing the full-length control rods to insert by gravity.

Manual reactor trip capability is afforded by two main control panel-mounted pushbuttons. One of these (on Control Panel CO-2) opens contacts in series with each of the four trip paths, de-energizing all M-contactors. The other pushbutton (on Control Panel CO-6) opens circuit breakers which provide AC input power to the M-contactor contacts and downstream clutch power supplies. Thus depressing either pushbutton will cause a reactor trip.

De-energizing the M-contactors removes AC power to the four clutch power supply inputs. Contacts from M-contactors M1 and M2 are in series with each other and in the AC power supply path to clutch power supplies PS1 and PS2 (these constitute a "trip leg"). M3 and M4 are similarly arranged with respect to clutch power supplies PS3 and PS4 (these constitute a second "trip leg"). Approximately half of the control rod clutches receive power from auctioneered clutch power supplies 1 and 3. The remaining control rod clutches receive clutch power from auctioneered clutch power supplies 2 and 4.

Matrix Logic refers to the matrix power supplies, trip channel bypass contacts, and interconnecting RPS cabinet matrix wiring between bistable and auxiliary trip unit relay contacts, including the matrix relays. Contacts in the bistable and auxiliary trip units are excluded from the Matrix Logic definition, since they are addressed as part of the instrumentation channel.

The Trip Initiation Logic consists of the M-contactor isolation transformers, all interconnecting wiring, and the M-contactors.

BASES

BACKGROUND

RPS Logic (continued)

Manual trip circuitry includes both manual reactor trip pushbuttons C0-2 and C0-6, and the interconnecting wiring necessary to effect deenergization of the clutch power supplies.

Neither the clutch power supplies nor the AC input power source to these supplies is considered as safety related. Operation may continue with one or two selective clutch power supplies de-energized.

It is possible to change the two-out-of-four RPS Logic to a two-out-of-three logic for a given input parameter in one channel at a time by Trip Channel Bypassing the RPS Trip unit output contacts in the Matrix Logic "Ladder." Trip Channel Bypassing a trip unit effectively shorts the trip unit relay contacts in the three matrices associated with that channel. Thus, the bypassed trip units will function normally, producing normal channel trip indication and annunciation, but a reactor trip will not occur unless two additional channels indicate a trip condition. Trip Channel Bypassing can be simultaneously performed on any number of parameters in any number of channels, providing each parameter is bypassed in only one channel at a time. A single bypass key for each trip function interlock prevents simultaneous Trip Channel Bypassing of the same parameter in more than one channel. Trip Channel Bypassing is normally employed during maintenance or testing.

Functional testing of the entire RPS, from trip unit input through the de-energizing of individual sets of clutch power supplies, can be performed either at power or during shutdown and is normally performed on a quarterly basis. FSAR Section 7.2 (Ref. 4) explains RPS testing in more detail.

APPLICABLE SAFETY ANALYSES

Reactor Protective System (RPS) Logic

The RPS Logic provides for automatic trip initiation to avoid exceeding the SLs during AOOs and to assist the ESF systems in ensuring acceptable consequences during accidents. All transients and accidents that call for a reactor trip assume the RPS Logic is functioning as designed.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Manual Trip

There are no accident analyses that take credit for the Manual Trip; however, the Manual Trip is part of the RPS circuitry. It is used by the operator to shut down the reactor whenever any parameter is rapidly trending toward its trip setpoint. A Manual Trip accomplishes the same results as any one of the automatic trip Functions.

The RPS Logic and Trip Initiation satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Reactor Protective System (RPS) Logic

Failures of individual trip unit relays and their contacts are addressed in LCO 3.3.1. This Specification addresses failures of the Matrix Logic not addressed in the above, such as the failure of matrix relay power supplies or the failure of the trip channel bypass contact in the bypass condition.

Loss of a single vital bus will de-energize one of the two power supplies in each of three matrices. Because of power supply auctioneering, all four matrix relays will remain energized in each affected matrix. This deenergization of up to three matrix power supplies due to a single failure is to be treated as a single channel failure.

Each of the four Trip Initiation Logic channels de-energizes one set of clutch power supplies if any of the six coincidence matrices de-energize their associated matrix relays. They thus perform a logical OR function. Trip Initiation Logic channels 1 and 2 receive AC power from preferred AC bus Y-30. Trip Initiation Logic channels 3 and 4 receive AC input power from preferred AC bus Y-40. Because of clutch power supply output auctioneering, it is possible to de-energize either input bus without de-energizing control rod clutches.

1. Matrix Logic

This LCO requires six channels of Matrix Logic to be OPERABLE in MODES 1 and 2, and in MODES 3, 4, and 5 when more than one full-length control rod is capable of being withdrawn and the PCS boron concentration is less than REFUELING BORON CONCENTRATION.

BASES

LCO (continued)

2. Trip Initiation Logic

This LCO requires four channels of Trip Initiation Logic to be OPERABLE in MODES 1 and 2, and in MODES 3, 4, and 5 when more than one full-length control rod is capable of being withdrawn and the PCS boron concentration is less than REFUELING BORON CONCENTRATION.

3. Manual Trip

The LCO requires both Manual Trip channels to be OPERABLE in MODES 1 and 2, and in MODES 3, 4, and 5 when more than one full-length control rod is capable of being withdrawn and the PCS boron concentration is less than REFUELING BORON CONCENTRATION.

Two independent pushbuttons are provided. Each pushbutton is considered to be a channel. Depressing either pushbutton interrupts power to all four clutch power supplies, tripping the reactor.

APPLICABILITY

The RPS Matrix Logic, Trip Initiation Logic, and Manual Trip are required to be OPERABLE in MODES 1 and 2, and in MODES 3, 4, and 5 when more than one full-length control rod capable of being withdrawn and the PCS boron concentration is less than REFUELING BORON CONCENTRATION. This ensures the reactor can be tripped when necessary, but allows for maintenance and testing when the reactor trip is not needed.

In MODES 3, 4, and 5 with no more than one full-length control rod capable of being withdrawn or the PCS boron concentration at REFUELING BORON CONCENTRATION, these Functions do not have to be OPERABLE. However, LCO 3.3.9, "Neutron Flux Monitoring Channels," does require neutron flux monitoring capability under these conditions.

BASES

ACTIONS

When the number of inoperable channels in a trip Function exceeds that specified in any related Condition associated with the same trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 is immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies if one Matrix Logic channel is inoperable. The channel must be restored to OPERABLE status within 48 hours. The Completion Time of 48 hours provides the operator time to take appropriate actions and still ensures that any risk involved in operating with a failed channel is acceptable. Operating experience has demonstrated that the probability of a random failure of a second Matrix Logic channel is low during any given 48 hour interval. If the channel cannot be restored to OPERABLE status within 48 hours, Condition E is entered.

B.1

Condition B applies if one Trip Initiation Logic channel is inoperable. The Required Action require de-energizing the affected clutch power supplies. This removes the need for the affected channel by performing its associated safety function. With the clutch power supplies associated with one initiation logic channel de-energized, the remaining two clutch power supplies prevent control rod clutches from de-energizing. The remaining clutch power supplies are in a one-out-of-two logic with respect to the remaining initiation logic channels in the clutch power supply path. This meets redundancy requirements, but testing on the OPERABLE channels cannot be performed without causing a reactor trip.

Required Action B.1 provides for de-energizing the affected clutch power supplies associated with the inoperable channel within a Completion Time of 1 hour.

BASES

ACTIONS (continued)

C.1

Condition C applies to the failure of one Manual Trip channel. With one manual reactor trip channel inoperable operation may continue until the reactor is shut down for other reasons. Repair during operation is not required because one OPERABLE channel is all that is required for safe operation. No safety analyses assume operation of the Manual trip.

The Manual Trip channels are not testable without actually causing a reactor trip, so even if the difficulty were corrected, the post maintenance testing necessary to declare the channel OPERABLE could not be completed during operation. Because of this, the Required Action is to restore the inoperable channel to OPERABLE status prior to entering MODE 2 from MODE 3 during the next plant startup.

D.1

Condition D applies to the failure of both Trip Initiation Logic channels affecting the same trip leg. The affected control rod drive clutch power supplies must be de-energized immediately. With both channels inoperable, the RPS Function is lost if the affected clutch power supplies are not de-energized. Therefore, immediate action is required to de-energize the affected clutch power supplies. The immediate Completion Time is appropriate since there could be a loss of safety function if the associated clutch power supplies are not de-energized.

E.1, E.2.1 and E.2.2

Condition E is entered if Required Actions associated with Condition A, B, C, or D are not met within the required Completion Time or if for one or more Functions more than one Manual Trip, Matrix Logic, or Trip Initiation Logic channel is inoperable for reasons other than Condition D.

In Condition E the reactor must be placed in a MODE in which the LCO does not apply. The Completion Time of 6 hours to be in MODE 3 is reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS

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

Required Actions E.2.1 and E.2.2 allow 6 hours to verify that no more than one full-length control rod is capable of being withdrawn or to verify that PCS boron concentration is at REFUELING BORON CONCENTRATION. The Completion Time is reasonable to place the plant in an operating condition in which the LCO does not apply.

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1

A CHANNEL FUNCTIONAL TEST on each RPS Logic channel is performed every 92 days to ensure the entire channel will perform its intended function when needed. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

This SR addresses the two tests associated with the RPS Logic: Matrix Logic and Trip Initiation Logic.

Matrix Logic Tests

These tests are performed one matrix at a time. They verify that a coincidence in the two input channels for each Function removes power from the matrix relays. During testing, power is applied to the matrix relay test coils and prevents the matrix relay contacts from assuming their de-energized state. The Matrix Logic tests will detect any short circuits around the bistable contacts in the coincidence logic such as may be caused by faulty bistable relay or trip channel bypass contacts.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

Trip Initiation Logic Tests

These tests are similar to the Matrix Logic tests, except that test power is withheld from one matrix relay at a time, allowing the initiation circuit to de-energize, de-energizing the affected set of clutch power supplies.

The Frequency of 92 days is based on the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Ref. 5).

SR 3.3.2.2

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

The Manual Trip Function is not tested at power. However, the simplicity of this circuitry and the absence of drift concern makes this Frequency adequate. Additionally, operating experience has shown that these components usually pass the Surveillance when performed once within 7 days prior to each reactor startup.

REFERENCES

1. 10 CFR 50, Appendix A
2. 10 CFR 100
3. FSAR, Figure 7-1
4. FSAR, Section 7.2
5. CEN-327, June 2, 1986, including Supplement 1, March 3, 1989

B 3.3 INSTRUMENTATION

B 3.3.3 Engineered Safety Features (ESF) Instrumentation

BASES

BACKGROUND

The ESF Instrumentation initiates necessary safety systems, based upon the values of selected plant parameters, to protect against violating core design limits and the Primary Coolant System (PCS) pressure boundary and to mitigate accidents.

The ESF circuitry generates the signals listed below when the monitored variables reach levels that are indicative of conditions requiring protective action. The inputs to each ESF actuation signal are also listed.

1. Safety Injection Signal (SIS).
    a. Containment High Pressure (CHP)
    b. Pressurizer Low Pressure
2. Steam Generator Low Pressure (SGLP);
    a. Steam Generator A Low Pressure
    b. Steam Generator B Low Pressure
3. Recirculation Actuation Signal (RAS);
    a. Safety Injection Refueling Water Tank (SIRWT) Low Level
4. Auxiliary Feedwater Actuation Signal (AFAS);
    a. Steam Generator A Low Level
    b. Steam Generator B Low Level
5. Containment High Pressure Signal (CHP);
    a. Containment High Pressure - Left Train
    b. Containment High Pressure - Right Train

BASES

BACKGROUND (continued)

6. Containment High Radiation Signal (CHR);

   a. Containment High Radiation

7. Automatic Bypass Removal

   a. Pressurizer Pressure Low Bypass

   b. Steam Generator A Low Pressure Bypass

   c. Steam Generator B Low Pressure Bypass

In the above list of actuation signals, the CHP and RAS are derived from pressure and level switches, respectively.

Equipment actuated by each of the above signals is identified in the FSAR, Chapter 7. (Ref. 1).

The ESF circuitry, with the exception of RAS, employs two-out-of-four logic. Four independent measurement channels are provided for each function used to generate ESF actuation signals. When any two channels of the same function reach their setpoint, actuating relays are energized which, in turn, initiate the protective actions. Two separate and redundant trains of actuating relays, each powered from separate power supplies, are utilized. These separate relay trains operate redundant trains of ESF equipment.

RAS logic consists of output contacts of the relays actuated by the SIRWT level switches arranged in a "one-out-of-two taken twice" logic. The contacts are arranged so that at least one low level signal powered from each station battery is required to initiate RAS. Loss of a single battery, therefore, cannot either cause or prevent RAS initiation.

The ESF logic circuitry contains the capability to manually block the SIS actuation logic and the SGLP action logic during normal plant shutdowns to avoid undesired actuation of the associated equipment. In each case, when three of the four associated measurement channels are below the block setpoint, pressing a manual pushbutton will block the actuation signal for that train. If two of the four of the measurement channels increase above the block setpoint, the block will automatically be removed.

BASES

BACKGROUND

7. Automatic Bypass Removal (continued)

The sensor subsystems, including individual channel actuation bistables, is addressed in this LCO. The actuation logic subsystems, manual actuation, and downstream components used to actuate the individual ESF components are addressed in LCO 3.3.4.

Measurement Channels

Measurement channels, consisting of pressure switches, field transmitters, or process sensors and associated instrumentation, provide a measurable electronic signal based upon the physical characteristics of the parameter being measured.

Four identical measurement channels are provided for each parameter used in the generation of trip signals. These are designated Channels A through D. Measurement channels provide input to ESF bistables within the same ESF channel. In addition, some measurement channels may also be used as inputs to Reactor Protective System (RPS) bistables, and most provide indication in the control room.

When a channel monitoring a parameter indicates an abnormal condition, the bistable monitoring the parameter in that channel will trip. In the case of RAS and CHP, the sensors are latching auxiliary relays from level and pressure switches, respectively, which do not develop an analog input to separate bistables. Tripping two or more channels monitoring the same parameter will actuate both channels of Actuation Logic of the associated ESF equipment.

Three of the four measurement and bistable channels are necessary to meet the redundancy and testability of GDC 21 in Appendix A to 10 CFR 50 (Ref. 2). The fourth channel provides additional flexibility by allowing one channel to be removed from service for maintenance or testing while still maintaining a minimum two-out-of-three logic.

Since no single failure will prevent a protective system actuation and no protective channel feeds a control channel, this arrangement meets the requirements of IEEE Standard 279 -1971 (Ref. 3).

BASES

BACKGROUND

Measurement Channels (continued)

The ESF Actuation Functions are generated by comparing a single measurement to a fixed bistable setpoint. The ESF Actuation Functions utilize the following input instrumentation:

- Safety Injection Signal (SIS)

  The Safety Injection Signal can be generated by any of three inputs: Pressurizer Low Pressure, Containment High Pressure, or Manual Actuation. Manual Actuation is addressed by LCO 3.3.4; Containment High Pressure is discussed below. Four instruments (channels A through D), monitor Pressurizer Pressure to develop the SIS actuation. Each of these instrument channels has two individually adjustable ESF bistable trip devices, one for the bypass removal circuit (discussed below) and one for SIS. Each ESF bistable trip device actuates two auxiliary relays, one for each actuation train. The output contacts from these auxiliary relays form the logic circuits addressed in LCO 3.3.4. The instrument channels associated with each Pressurizer Low Pressure SIS actuation bistable include the pressure measurement loop, the SIS actuation bistable, and the two auxiliary relays associated with that bistable. The bistables associated with automatic removal of the Pressurizer Low Pressure Bypass are discussed under Function 7.a, below.

- Low Steam Generator Pressure Signal (SGLP)

  There are two separate Low Steam Generator Pressure signals, one for each steam generator. For each steam generator, four instruments (channels A through D) monitor pressure to develop the SGLP actuation. Each of these instrument channels has two individually adjustable ESF bistable trip devices, one for the bypass removal circuit (discussed below) and one for SGLP. Each Steam SGLP bistable trip device actuates an auxiliary relay. The output contacts from these auxiliary relays form the SGLP logic circuits addressed in LCO 3.3.4. The instrument channels associated with each Steam Generator Low Pressure Signal bistable include the pressure measurement loop, the SGLP actuation bistable, and the auxiliary relay associated with that bistable. The bistables associated with automatic removal of the SGLP Bypass are discussed under Function 7.a, below.

BASES

BACKGROUND

Measurement Channels (continued)

- Recirculation Actuation Signal (RAS)

  There are four Safety Injection Refueling Water (SIRW) Tank level instruments used to develop the RAS signal. Each of these instrument channels actuates two auxiliary relays, one for each actuation train. The output contacts from these auxiliary relays form the logic circuits addressed in LCO 3.3.4. The SIRW Tank Low Level instrument channels associated with each RAS actuation bistable include the level instrument and the two auxiliary relays associated with that instrument.

- Auxiliary Feedwater Actuation Signal (AFAS)

  There are two separate AFAS signals (AFAS channels A and B), each one actuated on low level in either steam generator. For each steam generator, four level instruments (channels A through D) monitor level to develop the AFAS actuation signals. The output contacts from the bistables on these level channels form the SGLP logic circuits addressed in LCO 3.3.4. The instrument channels associated with each Steam Generator Low Level Signal bistable include the level measurement loop and the Low Level AFAS bistable.

- Containment High Pressure Actuation (CHP)

  The Containment High Pressure signal is actuated by two sets of four pressure switches, one set for each train. The output contacts from these pressure switches form the CHP logic circuits addressed in LCO 3.3.4.

BASES

BACKGROUND

Measurement Channels (continued)

- Containment High Radiation Actuation (CHR)

  The Safety Injection Signal can be generated by either of two inputs: High Radiation or Manual Actuation. Manual Actuation is addressed by LCO 3.3.4. Four radiation monitor instruments (channels A through D), monitor containment area radiation level to develop the CHR signal. Each CHR monitor bistable device actuates one auxiliary relay which has contacts in each CHR logic train addressed in LCO 3.3.4. The instrument channels associated with each CHR actuation bistable include the radiation monitor itself and the associated auxiliary relay.

- Automatic Bypass Removal Functions

  Pressurizer Low Pressure and Steam Generator Low Pressure logic circuits have the capability to be blocked to avoid undesired actuation when pressure is intentionally lowered during plant shutdowns. In each case these bypasses are automatically removed when the measured pressure exceeds the bypass permissive setpoint. The measurement channels which provide the bypass removal signal are the same channels which provide the actuation signal. Each of these pressure measurement channels has two bistables, one for actuation and one for the bypass removal Function. The pressurizer pressure channels include an auxiliary relay actuated by the bypass removal bistable. The logic circuits for Automatic Bypass Removal Functions are addressed by LCO 3.3.4.

Several measurement instrument channels provide more than one required function. Those sensors shared for RPS and ESF functions are identified in Table B 3.3.1-1. That table provides a listing of those shared channels and the Specifications which they affect.

BASES

BACKGROUND (continued)

Bistable Trip Units

There are four channels of bistables, designated A through D, for each ESF Function, one for each measurement channel.

The bistables for all required Functions, except CHP and RAS, receive an analog input from the measurement device, compare the analog input to trip setpoints, and provide contact output to the Actuation Logic. CHP and RAS are actuated by pressure switches and level switches respectively.

The Allowable Values are specified for each safety related ESF trip Function which is credited in the safety analysis. Nominal trip setpoints are specified in the plant procedures. The nominal setpoints are selected to ensure plant parameters do not exceed the Allowable Value if the instrument loop is performing as required. The methodology used to determine the nominal trip setpoints is also provided in plant documents. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the analytical limit determined in the safety analysis in order to account for uncertainties appropriate to the trip Function. These uncertainties are addressed as described in plant documents. A channel is inoperable if its actual setpoint is not within its Allowable Value.

Setpoints in accordance with the Allowable Value will ensure that Safety Limits of Chapter 2.0, "SAFETY LIMITS (SLs)," are not violated during Anticipated Operational Occurrences (AOOs) and that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the plant is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed.

ESF Instrument Channel Bypasses

The only ESF instrument channels with built-in bypass capability are the Low SG Level AFAS bistables. Those bypasses are effected by a key operated switch, similar to the RPS Trip Channel Bypasses. A bypassed Low SG Level channel AFAS bistable cannot perform its specified function and must be considered inoperable.

BASES

BACKGROUND

ESF Instrument Channel Bypasses (continued)

While there are no other built-in provisions for instrument channel bypasses in the ESF design (bypassing any other channel output requires opening a circuit link, lifting a lead, or using a jumper), this LCO includes requirements for OPERABILITY of the instrument channels and bistables which provide input to the Automatic Bypass Removal Logic channels required by LCO 3.3.4, "ESF Logic and Manual Initiation."

The Actuation Logic channels for Pressurizer Pressure and Steam Generator Low Pressure, however, have the ability to be manually bypassed when the associated pressure is below the range where automatic protection is required. These actuation logic channel bypasses may be manually initiated when three-out-of-four bypass permissive bistables indicate below their setpoint. When two-out-of-four of these bistables are above their bypass permissive setpoint, the actuation logic channel bypass is automatically removed. The bypass permissive bistables use the same four measurement channels as the blocked ESF function for their inputs.

APPLICABLE SAFETY ANALYSES

Each of the analyzed accidents can be detected by one or more ESF Functions. One of the ESF Functions is the primary actuation signal for that accident. An ESF Function may be the primary actuation signal for more than one type of accident. An ESF Function may also be a secondary, or backup, actuation signal for one or more other accidents. Functions not specifically credited in the accident analysis, serve as backups and are part of the NRC approved licensing basis for the plant.

BASES

APPLICABLE SAFETY ANALYSES (continued)

ESF protective Functions are as follows.

1. Safety Injection Signal (SIS)

The SIS ensures acceptable consequences during Loss of Coolant Accident (LOCA) events, including steam generator tube rupture, and Main Steam Line Breaks (MSLBs) or Feedwater Line Breaks (FWLBs) (inside containment). To provide the required protection, SIS is actuated by a CHP signal, or by two-out-of-four Pressurizer Low Pressure channels decreasing below the setpoint. SIS initiates the following actions:

a. Start HPSI & LPSI pumps;

b. Start component cooling water and service water pumps;

c. Initiate service water valve operations;

d. Initiate component cooling water valve operations;

e. Start containment cooling fans (when coincident with a loss of offsite power);

f. Enable Containment Spray Pump Start on CHP; and

g. Initiate Safety Injection Valve operations.

Each SIS logic train is also actuated by a contact pair on one of the CHP initiation relays for the associated CHP train.

2. Steam Generator Low Pressure Signal (SGLP)

The SGLP ensures acceptable consequences during an MSLB or FWLB by isolating the steam generator if it indicates a low steam generator pressure. The SGLP concurrent with or following a reactor trip, minimizes the rate of heat extraction and subsequent cooldown of the PCS during these events.

BASES

APPLICABLE SAFETY ANALYSES

2. Steam Generator Low Pressure Signal (SGLP) (continued)

One SGLP circuit is provided for each SG. Each SGLP circuit is actuated by two-out-of-four pressure channels on the associated SG reaching their setpoint. SGLP initiates the following actions:

a. Close the associated Feedwater Regulating valve and its bypass; and

b. Close both Main Steam Isolation Valves.

3. Recirculation Actuation Signal

At the end of the injection phase of a LOCA, the SIRWT will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the ECCS pumps is automatically switched to the containment recirculation sump. Switchover from SIRWT to the containment sump must occur before the SIRWT empties to prevent damage to the ECCS 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 pump suction.

Furthermore, early switchover must not occur to ensure sufficient borated water is injected from the SIRWT to ensure the reactor remains shut down in the recirculation mode. An SIRWT Low Level signal initiates the RAS.

RAS initiates the following actions:

a. Trip LPSI pumps (this trip can be manually bypassed);

b. Switch HPSI and containment spray pump suction from SIRWT to Containment Sump by opening sump CVs and closing SIRWT CVs; and

c. Adjust cooling water to component cooling heat exchangers.

BASES

APPLICABLE SAFETY ANALYSES

3. Recirculation Actuation Signal (continued)

The RAS signal is actuated by separate sensors from those which provide tank level indication. The allowable range of 21" to 27" above the tank floor corresponds to 1.1% to 3.3% indicated level. Typically the actual setting is near the midpoint of the allowable range.

4. Auxiliary Feedwater Actuation Signal

An AFAS initiates feedwater flow to both steam generators if a low level is indicated in either steam generator.

The AFAS maintains a steam generator heat sink during the following events:

- MSLB;
- FWLB;
- LOCA; and
- Loss of feedwater.

5. Containment High Pressure Signal (CHP)

The CHP signal closes all containment isolation valves not required for ESF operation and starts containment spray (if SIS enabled), ensuring acceptable consequences during LOCAs, control rod ejection events, MSLBs, or FWLBs (inside containment).

CHP is actuated by two-out-of-four pressure switches for the associated train reaching their setpoints. CHP initiates the following actions:

a. Containment Spray;

b. Safety Injection Signal;

c. Main Feedwater Isolation;

BASES

APPLICABLE SAFETY ANALYSIS

5. Containment High Pressure Signal (CHP) (continued)

   d. Main Steam Line Isolation;

   e. Control Room HVAC Emergency Mode; and

   f. Containment Isolation Valve Closure.

6. Containment High Radiation Signal (CHR)

   CHR is actuated by two-out-of-four radiation monitors exceeding their setpoints. CHR initiates the following actions to ensure acceptable consequences following a LOCA or control rod ejection event:

   a. Control Room HVAC Emergency Mode;

   b. Containment Isolation Valve Closure; and

   c. Block automatic starting of ECCS pump room sump pumps.

   During refueling operations, separate switch-selectable radiation monitors initiate CHR, as addressed by LCO 3.3.6.

7. Automatic Bypass Removal Functions

   The logic circuitry provides automatic removal of the Pressurizer Pressure Low and Steam Generator Pressure Low actuation signal bypasses. There are no assumptions in the safety analyses which assume operation of these automatic bypass removal circuits, and no analyzed events result in conditions where the automatic removal would be required to mitigate the event. The automatic removal circuits are required to assure that logic circuit bypasses will not be overlooked during a plant startup.

The ESF Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

The LCO requires all channel components necessary to provide an ESF actuation to be OPERABLE.

The Bases for the LCO on ESF Functions are addressed below.

1. Safety Injection Signal (SIS)

This LCO requires four channels of SIS Pressurizer Low Pressure to be OPERABLE in MODES 1, 2, and 3.

The setpoint was chosen so as to be low enough to avoid actuation during plant operating transients, but to be high enough to be quickly actuated by a LOCA or MSLB. The settings include an uncertainty allowance which is consistent with the settings assumed in the MSLB analysis (which bounds the settings assumed in the LOCA analysis).

2. Steam Generator Low Pressure Signal (SGLP)

This LCO requires four channels of Steam Generator Low Pressure Instrumentation for each SG to be OPERABLE in MODES 1, 2, and 3. However, as indicated in Table 3.3.3-1, Note (a), the SGLP Function is not required to be OPERABLE in MODES 2 or 3 if all Main Steam Isolation Valves (MSIVs) are closed and deactivated and all Main Feedwater Regulating Valves (MFRVs) and MFRV bypass valves are either closed and deactivated or isolated by closed manual valves.

The setpoint was chosen to be low enough to avoid actuation during plant operation, but be close enough to full power operating pressure to be actuated quickly in the event of a MSLB. The setting includes an uncertainty allowance which is consistent with the setting used in the Reference 4 analysis.

Each SGLP logic is made up of output contacts from four pressure bistables from the associated SG. When the logic circuit is satisfied, two relays are energized to actuate steam and feedwater line isolation.

BASES

LCO

2. Steam Generator Low Pressure Signal (SGLP) (continued)

This LCO applies to failures in the four sensor subsystems, including sensors, bistables, and associated equipment. Failures in the actuation subsystems are considered Actuation Logic failures and are addressed in LCO 3.3.4.

3. Recirculation Actuation Signal (RAS)

This LCO requires four channels of SIRWT Low Level to be OPERABLE in MODES 1, 2, and 3.

The setpoint was chosen to provide adequate water in the containment sump for HPSI pump net positive suction head following an accident, but prevent the pumps from running dry during the switchover.

The upper limit on the Allowable Value for this trip is set low enough to ensure RAS does not initiate before sufficient water is transferred to the containment sump. Premature recirculation could impair the reactivity control Function of safety injection by limiting the amount of boron injection. Premature recirculation could also damage or disable the recirculation system if recirculation begins before the sump has enough water.

The lower limit on the SIRWT Low Level trip Allowable Value is high enough to transfer suction to the containment sump prior to emptying the SIRWT.

4. Auxiliary Feedwater Actuation Signal (AFAS)

The AFAS logic actuates AFW to a SG on a SG Low Level in that SG.

The Allowable Value was chosen to assure that AFW flow would be initiated while the SG could still act as a heat sink and steam source, and to assure that a reactor trip would not occur on low level without the actuation of AFW.

BASES

LCO

4. Auxiliary Feedwater Actuation Signal (AFAS) (continued)

This LCO requires four channels for each steam generator of Steam Generator Low Level to be OPERABLE in MODES 1, 2, and 3.

5. Containment High Pressure Signal (CHP)

This LCO requires four channels of CHP to be OPERABLE for each of the associated ESF trains (left and right) in MODES 1, 2, 3 and 4.

The setpoint was chosen so as to be high enough to avoid actuation by containment temperature or atmospheric pressure changes, but low enough to be quickly actuated by a LOCA or a MSLB in the containment.

6. Containment High Radiation Signal (CHR)

This LCO requires four channels of CHR to be OPERABLE in MODES 1, 2, 3, and 4.

The setpoint is based on the maximum primary coolant leakage to the containment atmosphere allowed by LCO 3.4.13 and the maximum activity allowed by LCO 3.4.16. N^{16} concentration reaches equilibrium in containment atmosphere due to its short half-life, but other activity was assumed to build up. At the end of a 24 hour leakage period the dose rate is approximately 20 R/h as seen by the area monitors. A large leak could cause the area dose rate to quickly exceed the 20 R/h setting and initiate CHR.

7. Automatic Bypass Removal

The automatic bypass removal logic removes the bypasses which are used during plant shutdown periods, for Pressurizer Low Pressure and Steam Generator Low Pressure actuation signals.

The setpoints were chosen to be above the setpoint for the associated actuation signal, but well below the normal operating pressures.

BASES

LCO

7. Automatic Bypass Removal (continued)

This LCO requires four channels of Pressurizer Low Pressure bypass removal and four channels for each steam generator of Steam Generator Low Pressure bypass removal, to be OPERABLE in MODES 1, 2, and 3.

APPLICABILITY

All ESF Functions are required to be OPERABLE in MODES 1, 2, and 3. In addition, Containment High Pressure and Containment High Radiation are required to be operable in MODE 4.

In MODES 1, 2, and 3 there is sufficient energy in the primary and secondary systems to warrant automatic ESF System responses to:

- Close the main steam isolation valves to preclude a positive reactivity addition and containment overpressure;
- Actuate AFW to preclude the loss of the steam generators as a heat sink (in the event the normal feedwater system is not available);
- Actuate ESF systems to prevent or limit the release of fission product radioactivity to the environment by isolating containment and limiting the containment pressure from exceeding the containment design pressure during a design basis LOCA or MSLB; and
- Actuate ESF systems to ensure sufficient borated inventory to permit adequate core cooling and reactivity control during a design basis LOCA or MSLB accident.

The CHP and CHR Functions are required to be OPERABLE in MODE 4 to limit leakage of radioactive material from containment and limit operator exposure during and following a DBA.

The SGLP Function is not required to be OPERABLE in MODES 2 and 3, if all MSIVs are closed and deactivated and all MFRVs and MFRV bypass valves are either closed and deactivated or isolated by closed manual valves, since the SGLP Function is not required to perform any safety functions under these conditions.

BASES

APPLICABILITY (continued)

In lower MODES, automatic actuation of ESF Functions is not required, because adequate time is available for plant operators to evaluate plant conditions and respond by manually operating the ESF components.

LCO 3.3.6 addresses automatic Refueling CHR isolation during CORE ALTERATIONS or during movement of irradiated fuel.

In MODES 5 and 6, ESFAS initiated systems are either reconfigured or disabled for shutdown cooling operation. Accidents in these MODES are slow to develop and would be mitigated by manual operation of individual components.

ACTIONS

The most common causes of channel inoperability are outright failure of loop components or drift of those loop components which is sufficient to exceed the tolerance provided in the plant setpoint analysis. Loop component failures are typically identified by the actuation of alarms due to the channel failing to the "safe" condition, during CHANNEL CHECKS (when the instrument is compared to the redundant channels), or during the CHANNEL FUNCTIONAL TEST (when an automatic component might not respond properly). Typically, the drift of the loop components is found to be small and results in a delay of actuation rather than a total loss of function. Excessive loop component drift would, most likely, be identified during a CHANNEL CHECK (when the instrument is compared to the redundant channels) or during a CHANNEL CALIBRATION (when instrument loop components are checked against reference standards).

Typically, the drift is small and results in a delay of actuation rather than a total loss of function. Determination of setpoint drift is generally made during the performance of a CHANNEL FUNCTIONAL TEST when the process instrument is set up for adjustment to bring it to within specification. If the actual trip setpoint is not within the Allowable Value in Table 3.3.3-1, the channel is inoperable and the appropriate Condition(s) are entered.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value in Table 3.3.3-1, or the sensor, instrument loop, signal processing electronics, or ESF bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the plant must enter the Condition statement for the particular protection Function affected.

BASES

ACTIONS (continued)

When the number of inoperable channels in a trip Function exceeds those specified in any related Condition associated with the same trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A Note has been added to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each Function in Table 3.3.3-1. Completion Times for the inoperable channel of a Function will be tracked separately.

A.1

Condition A applies to the failure of a single bistable or associated instrumentation channel of one or more input parameters in each ESF Function except the RAS Function. Since the bistable and associated instrument channel combine to perform the actuation function, the Condition is also appropriate if both the bistable and associated instrument channel are inoperable.

ESF coincidence logic is normally two-out-of-four. If one ESF channel is inoperable, startup or power operation is allowed to continue as long as action is taken to restore the design level of redundancy.

If one ESF channel is inoperable, startup or power operation is allowed to continue, providing the inoperable channel actuation bistable is placed in trip within 7 days. The provision of four trip channels allows one channel to be inoperable in a non-trip condition up to the 7 day Completion Time allotted to place the channel in trip. Operating with one failed channel in a non-trip condition during operations, places the ESF Actuation Logic in a two-out-of-three coincidence logic.

If the failed channel cannot be restored to OPERABLE status in 7 days, the associated bistable is placed in a tripped condition. This places the function in a one-out-of-three configuration.

BASES

ACTIONS

A.1 (continued)

In this configuration, common cause failure of the dependent channel cannot prevent ESF actuation. The 7 day Completion Time is based upon operating experience, which has demonstrated that a random failure of a second channel occurring during the 7 day period is a low probability event.

Condition A is modified by a Note which indicates it is not applicable to the SIRWT Low Level Function.

B.1 and B.2

Condition B applies to the failure of two channels in any of the ESF Functions except the RAS Function.

With two inoperable channels, one channel actuation device must be placed in trip within the 8 hour Completion Time. Eight hours is allowed for this action since it must be accomplished by a circuit modification, or by removing power from a circuit component. With one channel of protective instrumentation inoperable, the ESF Actuation Logic Function is in two-out-of-three logic, but with another channel inoperable the ESF may be operating with a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, the second channel is placed in trip. This places the ESF in a one-out-of-two logic. If any of the other OPERABLE channels receives a trip signal, ESF actuation will occur.

One of the failed channels must be restored to OPERABLE status within 7 days, and the provisions of Condition A still applied to the remaining inoperable channel. Therefore, the channel that is still inoperable after completion of Required Action B.2 must be placed in trip if more than 7 days has elapsed since the channel's initial failure.

BASES

ACTIONS

B.1 and B.2 (continued)

Condition B is modified by a Note which indicates that it is not applicable to the SIRWT Low Level Function. The Required Action is also modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODES even though two channels are inoperable, with one channel tripped. MODE changes in this configuration are allowed, to permit maintenance and testing on one of the inoperable channels. In this configuration, the protection system is in a one-out-of-two logic, and the probability of a common cause failure affecting both of the OPERABLE channels during the 7 days permitted is remote.

C.1 and C.2

Condition C applies to one RAS SIRWT Low Level channel inoperable. The SIRWT low level circuitry is arranged in a "1-out-of-2 taken twice" logic rather than the more frequently used 2-out-of-4 logic. Therefore, Required Action C.1 differs from other ESF functions. With a bypassed SIRWT low level channel, an additional failure might disable automatic RAS, but would not initiate a premature RAS. With a tripped channel, an additional failure could cause a premature RAS, but would not disable the automatic RAS.

Since considerable time is available after initiation of SIS until RAS must be initiated, and since a premature RAS could damage the ESF pumps, it is preferable to bypass an inoperable channel and risk loss of automatic RAS than to trip a channel and risk a premature RAS.

The Completion Time of 8 hours allowed is reasonable because the Required Action involves a circuit modification.

Required Action C.2 requires that the inoperable channel be restored to OPERABLE status within 7 days. The Completion Time is reasonable based upon operating experience, which has demonstrated that a random failure of a second channel occurring during the 7 day period is a low probability event.

BASES

ACTIONS (continued)

D.1 and D.2

If the Required Actions and associated Completion Times of Condition A, B, or C are not met for Functions 1, 2, 3, 4, or 7, 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 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1 and E.2

If the Required Actions and associated Completion Times of Condition A, B, or C are not met for Functions 5 or 6, 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

The SRs for any particular ESF Function are found in the SRs column of Table 3.3.3-1 for that Function. Most functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION.

SR 3.3.3.1

A CHANNEL CHECK is performed once every 12 hours on each ESF input channel which is provided with an indicator to provide a qualitative assurance that the channel is working properly and that its readings are within limits. A CHANNEL CHECK is not performed on the CHP and SIRWT Low Level channels because they have no associated control room indicator.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between 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 the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. 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 only verify 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 Frequency of about once every shift is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of CHANNEL OPERABILITY during normal operational use of displays associated with the LCO required channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2

A CHANNEL FUNCTIONAL TEST is performed every 92 days to ensure the entire channel will perform its intended function when needed. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

This test is required to be performed each 92 days on ESF input channels provided with on-line testing capability. It is not required for the SIRWT Low Level channels since they have no built in test capability. The CHANNEL FUNCTIONAL TEST for SIRWT Low Level channels is performed each 18 months as part of the required CHANNEL CALIBRATION.

The CHANNEL FUNCTIONAL TEST tests the individual channels using an analog test input to each bistable.

Any setpoint adjustment shall be consistent with the assumptions of the current setpoint analysis.

The Frequency of 92 days is based on the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Reference 5).

SR 3.3.3.3

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive surveillances. CHANNEL CALIBRATIONS must be performed consistent with the setpoint analysis.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.3 (continued)

The as found and as left values must also be recorded and reviewed for consistency with the assumptions of the extension analysis. The requirements for this review are outlined in Reference 5.

The Frequency is based upon the assumption of an 18 month calibration interval for the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. FSAR, Chapter 7
2. 10 CFR 50, Appendix A
3. IEEE Standard 279-1971
4. FSAR, Chapter 14
5. CEN-327, June 2, 1986, including Supplement 1, March 3, 1989

B 3.3 INSTRUMENTATION

B 3.3.4 Engineered Safety Features (ESF) Logic and Manual Initiation

BASES

BACKGROUND

The ESF Instrumentation initiates necessary safety systems, based upon the values of selected plant parameters, to protect against violating core design limits and the Primary Coolant System (PCS) pressure boundary and to mitigate accidents.

The ESF circuitry generates the following signals listed below when the monitored variables reach levels that are indicative of conditions requiring protective action. The inputs to each ESF Actuation Signal are also listed.

1. Safety Injection Signal (SIS);
   a. Containment High Pressure (CHP)
   b. Pressurizer Low Pressure
2. Steam Generator Low Pressure Signal (SGLP)
   a. Steam Generator A Low Pressure
   b. Steam Generator B Low Pressure
3. Recirculation Actuation Signal (RAS);
   a. Safety Injection Refueling Water Tank (SIRWT) Low Level
4. Auxiliary Feedwater Actuation Signal (AFAS)
   a. Steam Generator A Low Level
   b. Steam Generator B Low Level

BASES

BACKGROUND (continued)

5. Containment High Pressure Signal (CHP);

   a. Containment High Pressure - Left Train

   b. Containment High Pressure - Right Train

6. Containment High Radiation Signal (CHR)

   a. Containment High Radiation

In the above list of actuation signals, the CHP and RAS are derived from pressure and level switches, respectively.

Equipment actuated by each of the above signals is identified in the FSAR, Chapter 7 (Ref. 1).

The ESF circuitry, with the exception of RAS, employs two-out-of-four logic. Four independent measurement channels are provided for each function used to generate ESF actuation signals. When any two channels of the same function reach their setpoint, actuating relays initiate the protective actions. Two separate and redundant trains of actuating relays, each powered from separate power supplies, are utilized. These separate relay trains operate redundant trains of ESF equipment. The actuation relays are considered part of the actuation logic addressed by this LCO.

RAS logic consists of output contacts of the relays actuated by the SIRWT Low Level switches arranged in a "one-out-of-two taken twice" logic. The contacts are arranged so that at least one low level signal powered from each station battery is required to initiate RAS. Loss of a single battery, therefore, cannot either cause or prevent RAS initiation.

The sensor subsystem, including individual channel bistables, is addressed in LCO 3.3.3, "Engineered Safety Features (ESF) Instrumentation." This LCO addresses the actuation subsystem manual actuation, and downstream components used to actuate the individual ESF functions, as defined in the following section.

BASES

BACKGROUND (continued)

ESF Logic

Each of the six ESF actuation signals in Table 3.3.4-1 operates two trains of actuating relays. Each train is capable of initiating the ESF equipment to meet the minimum requirements to provide all functions necessary to operate the system associated with the plant's capability to cope with abnormal events.

The SGLP logic circuitry includes provisions such that the SGLP automatic actuation Function may be bypassed if three-out-of-four Steam Generator (SG) pressure channels are below a bypass permissive setpoint. Similarly, the SIS automatic actuation on Pressurizer Low Pressure may be bypassed when three-out-of-four channels are below a permissive setpoint. This actuation bypassing is performed when the ESF Functions are no longer required for protection. These actuation bypasses are enabled manually when the permissive conditions are satisfied .

All actuation bypasses are automatically removed when enabling conditions are no longer satisfied. If an SIS or SGLP automatic actuation channel is bypassed, other than as allowed by Table 3.3.4-1, the channel cannot perform its required safety function and must be considered to be inoperable.

Testing of a major portion of the ESF circuits is accomplished while the plant is at power. More extensive sequencer and load testing may be done with the reactor shut down. The test circuits are designed to test the redundant circuits separately such that the correct operation of each circuit may be verified by either equipment operation or by sequence lights.

Manual Initiation

Manual ESF initiation capability is provided to permit the operator to manually actuate an ESF System when necessary.

Two control room mounted manual actuation switches are provided for SIS actuation, one for each train. Each SIS manual actuation switch affects one actuation channel, which actuates one train of SIS equipment.

There are no single manual controls provided to actuate CHP, however, CHP may be manually initiated using individual component controls.

BASES

BACKGROUND

Manual Initiation (continued)

Two control room mounted manual actuation switches are provided for CHR actuation, each switch affects both actuation channels, which actuates both CHR trains.

There are no single manual controls provided to actuate SGLP, however, SGLP may be manually initiated using individual component controls.

RAS is actuated by manually actuating the circuit "Test" switch, however, RAS may also be manually initiated using individual component controls.

Manual actuation of AFW may be accomplished through pushbutton actuation of each AFAS channel or by use of individual pump and valve controls. Each automatic AFAS actuation channel starts the AFW pumps in their starting sequence (if P-8A fails to start, a P-8C start signal is generated, and if P-8C also fails to start, a P-8B start signal is generated) and opens the associated flow control valves.

APPLICABLE SAFETY ANALYSES

Each of the analyzed accidents can be detected by one or more ESF Functions. One of the ESF Functions is the primary actuation signal for that accident. An ESF Function may be the primary actuation signal for more than one type of accident. An ESF 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 analysis, serve as backups to Functions and are part of the NRC staff approved licensing basis for the plant.

The manual initiation is not required by the accident analysis. The ESF logic must function in all situations where the ESF function is required (as discussed in the Bases for LCO 3.3.3).

Each ESF Function and its associated safety analyses are discussed in the Applicable Safety Analyses section of the Bases for LCO 3.3.3, ESF Instrumentation.

The ESF satisfies Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

The LCO requires that all components necessary to provide an ESF actuation be OPERABLE.

The Bases for the LCO on ESF automatic actuation Functions are addressed in LCO 3.3.3. Those associated with the Manual Initiation or Actuation Logic are addressed below.

ESF Logic and Manual Initiation Functions are required to be OPERABLE in MODES 1, 2, and 3, or in MODES 1, 2, 3, and 4, as appropriate, when the associated automatic initiation channels addressed by LCO 3.3.3 are required.

1. Safety Injection Signal (SIS)

SIS is actuated by manual initiation, by a CHP signal, or by two-out-of-four Pressurizer Low Pressure channels decreasing below the setpoint. Each Manual Initiation channel consists of one pushbutton which directly starts the SIS actuation logic for the associated train. Each SIS logic train is also actuated by a contact pair on one of the CHP initiation relays for the associated CHP train.

a. Manual Initiation

This LCO requires two channels of SIS Manual Initiation to be OPERABLE.

b. Actuation Logic

This LCO requires two channels of SIS Actuation Logic to be OPERABLE. Failures in the actuation subsystems are addressed in this LCO.

c. CHP Logic Trains

The CHP initiation relay (5P-x) input to the SIS logic is considered part of the SIS logic. Two channels, one per SIS train, must be OPERABLE.

BASES

LCO

1. Safety Injection Signal (SIS) (continued)

d. Automatic Bypass Removal

This LCO requires two channels of the automatic bypass removal logic for SIS Pressurizer Low Pressure to be OPERABLE. If an SIS automatic actuation channel is bypassed, other than as allowed by Table 3.3.4-1, the channel cannot perform its required safety function and must be considered to be inoperable.

As indicated by footnote (a), the Pressurizer Low Pressure logic train for each SIS train can be bypassed when three-out-of-four channels indicate below 1700 psia. This bypass prevents undesired actuation of SIS during a normal plant cooldown. The bypass signal is automatically removed when two-out-of-four channels exceed the setpoint, in accordance with the philosophy of removing bypasses when the enabling conditions are no longer satisfied.

The bypass permissive is set low enough so as not to be enabled during normal plant operation, but high enough to allow bypassing prior to reaching the trip setpoint.

2. Steam Generator Low Pressure Signal (SGLP)

a. Manual Initiation

This LCO requires two channels of SGLP Manual Initiation to be OPERABLE. As indicated by footnote (c), there is no manual control which actuates the SGLP logic circuits. The actuated components must be individually actuated using control room manual controls.

b. Actuation Logic

This LCO requires two channels of SGLP Actuation Logic to be OPERABLE, one for each SG.

BASES

LCO

2. Steam Generator Low Pressure Signal (SGLP) (continued)

c. Automatic Bypass Removal

This LCO requires two channels, one for each SG, of the SGLP automatic bypass removal logic to be OPERABLE. If an SIS automatic actuation channel is bypassed, other than as allowed by Table 3.3.4-1, the channel cannot perform its required safety function and must be considered to be inoperable.

As indicated by footnote (b), the SGLP from each SG may be bypassed when three-out-of-four channels indicate below 565 psia. This bypass prevents undesired actuation during a normal plant cooldown. The bypass signal is automatically removed when two-out-of-four channels exceed the setpoint, in accordance with the philosophy of removing bypasses when the enabling conditions are no longer satisfied.

The bypass permissive is set low enough so as not to be enabled during normal plant operation, but high enough to allow bypassing prior to reaching the trip setpoint.

3. Recirculation Actuation Signal (RAS)

a. Manual Initiation

This LCO requires two channels of RAS Manual Initiation to be OPERABLE. RAS is actuated by manually actuating the circuit "Test" switches.

b. Actuation Logic

This LCO requires two channels of RAS Actuation Logic to be OPERABLE.

BASES

LCO (continued)

4. Auxiliary Feedwater Actuation Signal (AFAS)

a. Manual Initiation

This LCO requires two channels of AFAS Manual Initiation to be OPERABLE. Each train of AFAS may be manually initiated with either of two sets of controls. Only one set of manual controls is required to be OPERABLE for each AFW train. One set of controls are the pushbuttons provided to actuate each train on the C-11 panel; the other set of controls are those manual controls provided on C-01 for each AFW pump and flow control valve.

b. Actuation Logic

This LCO requires two channels of AFAS Actuation Logic to be OPERABLE.

5. Containment High Pressure Signal (CHP)

a. Manual Initiation

As indicated by footnote (c), this LCO requires the manual controls necessary to actuate those valves and components actuated by an automatic CHP to be OPERABLE.

b. Actuation Logic

This LCO requires two channels of CHP Actuation Logic to be OPERABLE.

6. Containment High Radiation Signal (CHR)

a. Manual Initiation

This LCO requires two channels of CHR Manual Initiation to be OPERABLE. Pushbuttons are available for manual actuation of each CHR logic train.

BASES

LCO

6. Containment High Radiation Signal (CHR) (continued)

b. Actuation Logic

This LCO requires two channels of CHR Actuation Logic to be OPERABLE.

APPLICABILITY

ESF Functions are required to be OPERABLE in MODES 1, 2, and 3 or MODES 1, 2, 3, and 4 as specified in Table 3.3.4-1. In MODES 1, 2, and 3, there is sufficient energy in the primary and secondary systems to warrant automatic ESF System responses to:

- Close the MSIVs to preclude a positive reactivity addition and containment overpressure;
- Actuate AFW to preclude the loss of the steam generators as a heat sink (in the event the normal feedwater system is not available);
- Actuate ESF systems to prevent or limit the release of fission product radioactivity to the environment by isolating containment and limiting the containment pressure from exceeding the containment design pressure during a design basis LOCA or MSLB; and
- Actuate ESF systems to ensure sufficient borated inventory to permit adequate core cooling and reactivity control during a design basis LOCA or MSLB accident.

The CHP and CHR Functions are also required to be OPERABLE in MODE 4 to limit leakage of radioactive material from containment and limit operator exposure during and following a DBA.

The SGLP Function is not required to be OPERABLE in MODES 2 and 3, if all MSIVs are closed and deactivated and all MFRVs and MFRV bypass valves are either closed and deactivated or isolated by closed manual valves, since the SGLP Function is not required to perform any safety function under these conditions.

BASES

APPLICABILITY (continued)

In MODES 5 and 6, automatic actuation of ESF Functions is not required, because adequate time is available for plant operators to evaluate plant conditions and respond by manually operating the ESF components if required. In these MODES, ESF initiated systems are either reconfigured or disabled for shutdown cooling operation. Accidents in these MODES are slow to develop and would be mitigated by manual operation of individual components.

ACTIONS

When the number of inoperable channels in a trip Function exceeds those specified in any related Condition associated with the same trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered, if applicable in the current MODE of operation.

A Note has been added to the ACTIONS to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each Function in Table 3.3.4-1 in the LCO. Completion Times for the inoperable channel of a Function will be tracked separately.

A.1

Condition A applies to one Manual Initiation, Bypass Removal, or Actuation Logic channel inoperable. The channel must be restored to OPERABLE status to restore redundancy of the ESF Function. The 48 hour Completion Time is commensurate with the importance of avoiding the vulnerability of a single failure in the only remaining OPERABLE channel.

B.1 and B.2

If two Manual Initiation, Bypass Removal, or Actuation Logic channels are inoperable for Functions 1, 2, 3, or 4, or if the Required Action and associated Completion Time of Condition A cannot be met for Function 1, 2, 3, or 4, the reactor 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 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

Condition C is entered when one or more Functions have two Manual Initiation or Actuation Logic channels inoperable for Functions 5 or 6, or when the Required Action and associated Completion Time of Condition A are not met for Functions 5 or 6. If Required Action A.1 cannot be met within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

A functional test of each SIS actuation channel must be performed each 92 days. This test is to be performed using the installed control room test switches and test circuits for both "with standby power" and "without standby power". When testing the "with standby power" circuits, proper operation of the "SIS-X" relays must be verified; when testing the "without standby power" circuits, proper operation of the "DBA sequencer" and the associated logic circuit must be verified. The test circuits are designed to block those SIS functions, such as injection of concentrated boric acid, which would interfere with plant operation.

The Frequency of 92 days is based on plant operating experience.

SR 3.3.4.2

A CHANNEL FUNCTIONAL TEST of each AFAS Actuation Logic Channel is performed every 92 days to ensure the channel will perform its intended function when needed. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2 (continued)

Instrumentation channel tests are addressed in LCO 3.3.3.

SR 3.3.4.2 addresses Actuation Logic tests of the AFAS using the installed test circuits.

The Frequency of 92 days for SR 3.3.4.2 is in agreement with the conclusions of the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Ref. 2).

SR 3.3.4.3

A CHANNEL FUNCTIONAL TEST is performed on the manual ESF initiation channels, Actuation Logic channels, and bypass removal channels for specified ESF Functions. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

This Surveillance verifies that the required channels will perform their intended functions when needed.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at a Frequency of once every 18 months.

REFERENCES

1. FSAR, Chapter 7

2. CEN-327, June 2, 1986, including Supplement 1, March 3, 1989

B 3.3 INSTRUMENTATION

B 3.3.5 Diesel Generator (DG) - Undervoltage Start (UV Start)

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or insufficiently stable to allow safe plant operation. Undervoltage protection will generate a UV Start in the event a Loss of Voltage or Degraded Voltage condition occurs. There are two UV Start Functions for each 2.4 kV vital bus.

Undervoltage protection and load shedding features for safety-related buses at the 2,400 V and lower voltage levels are designed in accordance with 10 CFR 50, Appendix A, General Design Criterion 17 (Ref. 1) and the following features:

1. Two levels of automatic undervoltage protection from loss or degradation of offsite power sources are provided. The first level (loss of voltage) provides normal loss of voltage protection. The second level of protection (degraded voltage) has voltage and time delay set points selected for automatic trip of the offsite sources to protect safety-related equipment from sustained degraded voltage conditions at all bus voltage levels. Coincidence logic is provided to preclude spurious trips.

2. The undervoltage protection system automatically prevents load shedding of the safety-related buses when the emergency generators are supplying power to the safeguards loads.

3. Control circuits for shedding of Class 1E and non-Class 1E loads during a Loss of Coolant Accident (LOCA) themselves are Class 1E or are separated electrically from the Class 1E portions.

BASES

BACKGROUND (continued)

Description

Each 2,400 V Bus (1C and 1D) is equipped with two levels of undervoltage protection relays (Ref. 2). The first level (Loss of Voltage Function) relays 127-1 and 127-2 are set at approximately 77% of rated voltage with an inverse time relay. One of these relays measures voltage on each of the three phases. They protect against sudden loss of voltage as sensed on the corresponding bus using a three-out-of-three coincidence logic. The actuation of the associated auxiliary relays will trip the associated bus incoming circuit breakers, start its associated DG, initiate bus load shedding, and activate annunciators in the control room. The DG circuit breaker is closed automatically upon establishment of satisfactory voltage and frequency by the use of associated voltage sensing relay 127D-1 or 127D-2.

The second level of undervoltage protection (Degraded Voltage Function) relays 127-7 and 127-8 are set at approximately 93% of rated voltage, with one relay monitoring each of the three phases. These relays protect against sustained degraded voltage conditions on the corresponding bus using a three-out-of-three coincidence logic. These relays have a built-in 0.65 second time delay, after which the associated DG receives a start signal and annunciators in the control room are actuated. If a bus undervoltage exists after an additional six seconds, the associated bus incoming circuit breakers will be tripped and a bus load shed will be initiated.

Trip Setpoints

The trip setpoints are based on the analytical limits presented in References 3 and 4, and justified in Reference 5. 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, and instrument drift, setpoints specified in SR 3.3.5.2 are conservatively adjusted with respect to the analytical limits. A detailed analysis of the degraded voltage protection is provided in References 3 and 4.

The specified setpoints will ensure that the consequences of accidents will be acceptable, providing the plant is operated from within the LCOs at the onset of the accident and the equipment functions as designed.

BASES

APPLICABLE SAFETY ANALYSES

The DG - UV Start is required for Engineered Safety Features (ESF) systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Systems.

Accident analyses credit the loading of the DG based on a loss of offsite power during a LOCA. The diesel loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. This delay time includes contributions from the DG start, DG loading, and Safety Injection System component actuation.

The required channels of UV Start, in conjunction with the ESF systems powered from the DGs, provide plant protection in the event of any of the analyzed accidents discussed in Reference 6, in which a loss of offsite power is assumed. UV Start channels are required to meet the redundancy and testability requirements of GDC 21 in 10 CFR 50, Appendix A (Ref. 1).

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 include the appropriate DG loading and sequencing delay.

The DG - UV Start channels satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The LCO for the DG - UV Start requires that three channels per bus of each UV Start instrumentation Function be OPERABLE when the associated DG is required to be OPERABLE. The UV Start supports safety systems associated with ESF actuation.

The Bases for the trip setpoints are as follows:

The voltage trip setpoint is set low enough such that spurious trips of the offsite source due to operation of the undervoltage relays are not expected for any combination of plant loads and normal grid voltages.

BASES

LCO (continued)

This setpoint at the 2,400 V bus and reflected down to the 480 V buses has been verified through an analysis to be greater than the minimum allowable motor voltage (90% of nominal voltage). Motors are the most limiting equipment in the system. MCC contactor pickup and drop-out voltage is also adequate at the setpoint values. The analysis ensures that the distribution system is capable of starting and operating all safety-related equipment within the equipment voltage rating at the allowed source voltages. The power distribution system model used in the analysis has been verified by actual testing (Refs. 5 and 7).

The time delays involved will not cause any thermal damage as the setpoints are within voltage ranges for sustained operation. They are long enough to preclude trip of the offsite source caused by the starting of large motors and yet do not exceed the time limits of ESF actuation assumed in FSAR Chapter 14 (Ref. 6) and validated by Reference 8.

Calibration of the undervoltage relays verify that the time delay is sufficient to avoid spurious trips.

APPLICABILITY

The DG - UV Start actuation Function is required to be OPERABLE whenever the associated DG is required to be OPERABLE per LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, "AC Sources - Shutdown," so that it can perform its function on a loss of power or degraded power to the vital bus.

ACTIONS

A DG - UV Start channel is inoperable when it does not satisfy the OPERABILITY criteria for the channel's Function.

In the event a channel's trip setpoint is found nonconservative with respect to the specified setpoint, or the channel is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition entered. The required channels are specified on a per DG basis.

BASES

ACTIONS (continued)

A.1

Condition A applies if one or more of the three phase UV sensors or relay logic is inoperable for one or more Functions (Degraded Voltage or Loss of Voltage) per DG bus.

The affected DG must be declared inoperable and the appropriate Condition(s) entered. Because of the three-out-of-three logic in both the Loss of Voltage and Degraded Voltage Functions, the appropriate means of addressing channel failure is declaring the DG inoperable, and effecting repair in a manner consistent with other DG failures.

Required Action A.1 ensures that Required Actions for the affected DG inoperabilities are initiated. Depending upon plant MODE, the actions specified in LCO 3.8.1 or LCO 3.8.2, as applicable, are required immediately.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

A CHANNEL FUNCTIONAL TEST is performed on each UV Start logic channel every 18 months to ensure that the logic channel will perform its intended function when needed. The Undervoltage sensing relays are tested by SR 3.3.5.2. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The Frequency of 18 months is based on the plant conditions necessary to perform the test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.2

A CHANNEL CALIBRATION performed each 18 months verifies the accuracy of each component within the instrument channel. This includes calibration of the undervoltage relays and demonstrates that the equipment falls within the specified operating characteristics defined by the manufacturer.

The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with the setpoint analysis.

The Frequency of 18 months is based on the plant conditions necessary to perform the test.

REFERENCES

1. 10 CFR 50, Appendix A GDCs 17 and 21
2. FSAR, Section 8.6
3. CPCo Analysis EA-ELEC-VOLT-033
4. CPCo Analysis EA-ELEC-VOLT-034
5. CPCo Analysis EA-ELEC-VOLT-17
6. FSAR, Chapter 14
7. CPCo Analysis EA-ELEC-VOLT-13
8. CPCo Analysis A-NL-92-111

B 3.3 INSTRUMENTATION

B 3.3.6 Refueling Containment High Radiation (CHR) Instrumentation

BASES

BACKGROUND

This LCO addresses Refueling CHR actuation. When the Refueling CHR Monitors are enabled by their keylock switches, a CHR actuation may be automatically initiated by a signal from either of the Refueling CHR monitors or manually by actuation of either of the control room "CHR Manual Initiate" pushbuttons (pushing either Manual Initiate pushbutton will actuate both trains of CHR). A CHR signal initiates the following actions:

a. Control Room HVAC Emergency Mode;

b. Containment Isolation Valve Closure; and

c. Block automatic starting of Engineered Safeguards pump room sump pumps.

The Refueling CHR signal provides automatic containment isolation valve closure during refueling operations, using two radiation monitors located in the refueling area of the containment (elevation 649 ft). The monitors are part of the plant area monitoring system and employ one-out-of-two logic for isolation. During normal operation these monitors are disconnected from the CHR relays and will not initiate a CHR signal. A switch is provided to connect the Refueling CHR monitors into the CHR actuation circuit, so that CHR actuation can be initiated by these monitors during refueling .

BASES

BACKGROUND (continued)

Each monitor actuates one train of CHR logic when containment radiation exceeds the setpoint. Two separate keylock switches, one per train, enable the Refueling CHR input to the CHR logic when switched to the "Refueling" position. Each Refueling CHR channel, associated keylock switch, and initiation circuit input to the CHR logic thus forms a one-out-of-one logic input to its associated CHR actuation logic train. The Refueling CHR isolation instrumentation is separate from the CHR instrumentation addressed in LCO 3.3.3, "ESF Instrumentation." However, the Refueling CHR Instrumentation does operate the same CHR actuation relays as the two-out-of-four CHR logic addressed in LCO 3.3.4. This LCO is not included in LCOs 3.3.3 and 3.3.4 because of the differences in APPLICABILITY and the single channel nature of the Refueling CHR input. The Refueling CHR signal performs the automatic containment isolation valve closure Function during refueling operations required by LCO 3.9.3, "Containment Penetrations."

The Refueling CHR Instrumentation provides protection from release of radioactive gases and particulates from the containment in the event a fuel assembly should be severely damaged during handling.

The Refueling CHR Instrumentation will detect any abnormal radiation levels in the containment refueling area and will initiate purge valve closure to limit the release of radioactivity to the environment. The containment purge supply and exhaust valves are closed on a CHR signal when a high radiation level in containment is detected.

The Refueling CHR Instrumentation includes two independent, redundant actuation subsystems, as described above. Reference 1 describes the Refueling CHR circuitry.

Trip Setpoint

No required setpoint is specified because these instruments are not assumed to function by any of the safety analyses. Typically, the instruments are set at about 25 mR/hr above expected background for planned operations (including movement of the reactor vessel head or internals).

BASES

APPLICABLE SAFETY ANALYSES

The Refueling CHR Instrumentation isolates containment in the event that area radiation exceeds an established level following a fuel handling accident. This ensures the radioactive materials are not released directly to the environment and significantly reduces the offsite doses from those calculated by the safety analyses, which do not credit containment isolation (Ref. 2). Either way, i.e., with or without containment isolation, the offsite doses remain within the guidelines of 10 CFR 100.

The Refueling CHR Instrumentation is not required by the fuel handling accident analyses to maintain offsite doses within the guidelines of 10 CFR 100, but containment isolation would provide a significant reduction of the resulting offsite doses. Therefore, the Refueling CHR Instrumentation satisfies the requirements of Criterion 4 of 10 CFR 50.36(c)(2).

LCO

The LCO for the Refueling CHR Instrumentation requires that two channels of refueling CHR instrumentation and two channels of CHR manual initiation be OPERABLE, including the logic components necessary to initiate Refueling CHR Isolation. The CHR setpoint is chosen to be high enough to avoid inadvertent actuation in the event of normal background radiation fluctuations during fuel handling and movement of the reactor internals, but low enough to alarm and isolate the containment in the event of a Design Basis fuel handling accident.

APPLICABILITY

In MODE 5 or 6, the Refueling CHR isolation of containment isolation valves is not normally required to be OPERABLE. However, during CORE ALTERATIONS or during movement of irradiated fuel within containment, there is the possibility of a fuel handling accident requiring containment isolation on high radiation in containment. Accordingly, the Refueling CHR Instrumentation must be OPERABLE during CORE ALTERATIONS and when moving any irradiated fuel in containment.

In MODES 1, 2, 3 and 4, both the Containment High Pressure (CHP) and CHR signals provide containment isolation as discussed in the Bases for LCO 3.3.3 and LCO 3.3.4.

BASES

ACTIONS

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

Condition A applies to the failure of one Refueling CHR monitor channel, one CHR Manual Initiate channel, or one of each. The Required Action allows either initiation of a CHR signal by placing the inoperable channel in trip (which accomplishes the safety function of the inoperable channel), or suspension of CORE ALTERATIONS and movement of irradiated fuel assemblies within containment (which places the plant in a condition where the LCO does not apply). The Completion Time of 4 hours is acceptable because one additional channel of each Function remains operable during that period and the probability of an additional failure occurring during this period is very small.

The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

B.1 and B.2

Condition B applies when either no automatic Refueling CHR or no Manual CHR (or neither) is available. The Required Action is to immediately suspend CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. This places the plant in a condition where the LCO does not apply. The Completion Time is warranted on the basis that at least one containment isolation Function is completely lost.

The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1 (continued)

Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or actual differing radiation levels at the two detector locations. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

The Frequency, about once every shift, is based on operating experience that demonstrates the rarity of channel failure. Since the probability of two random failures in redundant channels in any 12 hour period is low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of the displays associated with the LCO required channels.

SR 3.3.6.2

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

The Frequency of 31 days is based on plant operating experience with regard to channel OPERABILITY, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3

A CHANNEL FUNCTIONAL TEST is performed on each CHR Manual Initiation channel to ensure it will perform its intended function.

The Frequency of 18 months is based on plant operating experience with regard to channel OPERABILITY, and is consistent with the testing of other manually actuated functions.

SR 3.3.6.4

A CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests.

The Frequency is based upon the assumption of an 18 month calibration interval in the setpoint determination.

REFERENCES

1. FSAR, Section 7.3
2. FSAR, Section 14.19

B 3.3 INSTRUMENTATION

B 3.3.7 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the Post Accident Monitoring (PAM) instrumentation is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety Functions for Design Basis Events.

The OPERABILITY of the PAM instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident.

The availability of PAM instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. The required instruments are identified in FSAR Appendix 7C (Ref. 1) and address the recommendations of Regulatory Guide 1.97 (Ref. 2), as required by Supplement 1 to NUREG-0737, "TMI Action Items" (Ref. 3).

Type A variables are included in this LCO because they provide the primary information required to permit the control room operator to take specific manually controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions for Design Basis Accidents (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 potential for causing a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public and for an estimate of the magnitude of any impending threat.

BASES

BACKGROUND (continued)

These key variables are identified in the plant specific Regulatory Guide 1.97 analyses (Ref. 1). This analysis identified the plant specific Type A and Category 1 variables and provided justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.7-1 are discussed in the LCO Bases.

APPLICABLE SAFETY ANALYSES

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

- Perform the diagnosis specified in the emergency operating procedures. These variables are restricted to preplanned actions for the primary success path of DBAs; and
- Take the specified, preplanned, manually controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions.

The PAM instrumentation also ensures OPERABILITY of Category I, non-Type A variables. This ensures the control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;
- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public as well as to obtain an estimate of the magnitude of any impending threat.

Category I, non-Type A PAM instruments are retained in the Specification because they are intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I variables are important in reducing public risk.

PAM instrumentation that satisfies the definition of Type A in Regulatory Guide 1.97 meets Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

LCO 3.3.7 requires at least two OPERABLE channels for all Functions except Containment Isolation Valve Position Indication. This is to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the plant and to bring the plant to, and maintain it in, a safe condition following that accident.

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

For Containment Isolation Valve Position indication, the important information is the status of the containment penetrations. The LCO requires one position indication channel for each containment isolation valve listed in FSAR Appendix 7C (Ref. 1).

Listed below are discussions of the specified instrument Functions listed in Table 3.3.7-1. Component identifiers of the sensors, indicators, power supplies, displays, and recorders in each instrument loop are found in Reference 1.

1, 2. Primary Coolant System (PCS) Hot and Cold Leg Temperature (wide range)

PCS wide range Hot and Cold Leg Temperatures are Type B, Category 1 variables provided for verification of core cooling and long term surveillance.

Reactor outlet temperature inputs to the PAM are provided by two wide range resistance elements and associated transmitters (one in each loop). The channels provide indication over a range of 50°F to 700°F.

3. Wide Range Neutron Flux

Wide Range Neutron Flux indication is a Type B, Category 1 variable, and is provided to verify reactor shutdown.

4. Containment Floor Water Level (wide range)

Wide range Containment Floor Water Level is a Type B, Category 1 variable, and is provided for verification and long term surveillance of PCS integrity.

BASES

LCO (continued)

5. Subcooled Margin Monitor

The Subcooled Margin Monitor (SMM) is a Type A, Category 1 variable used to identify conditions which require tripping of the primary coolant pumps and throttling of safety injection flows. Each SMM channel uses a number of PCS pressure and temperature inputs to determine the degree of PCS subcooling or superheat.

6. Pressurizer Level (Wide Range)

Pressurizer Level is a Type A, Category 1 variable, and is used to determine whether to terminate Safety Injection (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 plant conditions necessary to establish natural circulation in the PCS and to verify that the plant is maintained in a safe shutdown condition.

7. Containment Hydrogen Monitors

Containment Hydrogen Monitors are provided to detect high hydrogen concentration conditions (a Type A, Category 1 variable) that represent a potential for containment breach and are used to determine when to place the hydrogen recombiners in operation. This variable is also important in verifying the adequacy of mitigating actions.

8. Condensate Storage Tank (CST) Level

CST Level is a Type D, Category 1 variable, and is provided to ensure water supply for AFW. The CST provides the safety grade water supply for the AFW System. Inventory is monitored by a 0 to 100% level indication. CST Level is displayed on a control room indicator. In addition, a control room annunciator alarms on low level.

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.

BASES

LCO (continued)

9. Primary Coolant System Pressure (wide range)

PCS wide range pressure is a Type A, Category 1 variable provided for verification of core cooling and PCS integrity long term surveillance.

Wide range PCS loop pressure is measured by pressure transmitters with a span of 0 psia to 3000 psig. Redundant monitoring capability is provided by two channels of instrumentation. Control room indications are provided on C12 and C02.

10. Containment Pressure (wide range)

Wide range Containment Pressure is a Type C, Category 1 variable, and is provided for verification of PCS and containment OPERABILITY. It is also an input to decisions for initiating containment spray.

11, 12. Steam Generator Water Level (wide range)

Wide range Steam Generator Water Level is a Type A, Category 1 variable, and is provided to monitor operation of decay heat removal via the steam generators. The steam generator level instrumentation covers a span extending from the tube sheet to the steam separators, with an indicated range of -140% to +150%. Redundant monitoring capability is provided by two channels of instrumentation for each SG.

Operator action for maintenance of heat removal is based on the control room indication of Steam Generator Water Level. The indication is used during a SG tube rupture to determine which SG has the ruptured tube. It is also used to determine when to initiate once through cooling on low water level.

13, 14. SG Pressure

Steam Generator Pressure is a Type A, Category 1 variable used in accident identification, including Loss of Coolant, and Steam Line Break. Redundant monitoring capability is provided by two channels of instrumentation for each SG.

BASES

LCO (continued)

15. Containment Isolation Valve Position

Containment Isolation Valve (CIV) Position is a Type B, Category 1 variable, and is provided for verification of containment OPERABILITY.

CIV position is provided for verification of containment integrity. In the case of CIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each CIV listed in FSAR Appendix 7C (Ref. 1). This is sufficient to redundantly verify the isolation status of each associated penetration via indicated status of the CIVs, and by knowledge of a passive (check) valve or a closed system boundary.

If a penetration flow path is isolated, position indication for the CIV(s) in the associated penetration flow path is not needed to determine status. Therefore, as indicated in Note (a) the position indication for valves in an isolated penetration flow path is not required to be OPERABLE.

16, 17, 18, 19. Core Exit Temperature

Core Exit Temperature is a Type C, Category 1 variable, and is provided for verification and long term surveillance of core cooling.

Each Required Core Exit Thermocouple (CET) channel consists of a single environmentally qualified thermocouple.

The design of the Incore Instrumentation System includes a Type K (chromel alumel) thermocouple within each of the incore instrument detector assemblies.

The junction of each thermocouple is located above the core exit, inside the incore detector assembly guide tube, that supports and shields the incore instrument detector assembly string from flow forces in the outlet plenum region. These core exit thermocouples monitor the temperature of the reactor coolant as it exits the fuel assemblies.

The core exit thermocouples have a usable temperature range from 32°F to 2300°F, although accuracy is reduced at temperatures above 1800°F.

BASES

LCO (continued)

20. Reactor Vessel Water Level

Reactor Vessel Water Level is monitored by the Reactor Vessel Level Monitoring System (RVLMS) and is a Type B, Category 1 variable provided for verification and long term surveillance of core cooling.

The RVLMS 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. The collapsed level is obtained over the same temperature and pressure range as the saturation measurements, thereby encompassing all operating and accident conditions where it must function. Also, it functions during the recovery interval. Therefore, it is designed to survive the high steam temperature that may occur during the preceding core recovery interval.

The level range extends from the top of the vessel down to the top of the fuel alignment plate. A total of eight Heated Junction Thermocouple (HJTC) pairs are employed in each of the two RVLMS channels. Each pair consists of a heated junction TC and an unheated junction TC. The differential temperature at each HJTC pair provides discrete indication of uncovery at the HJTC pair location. This indication is displayed using LEDs in the control room. This provides the operator with adequate indication to track the progression of the accident and to detect the consequences of its mitigating actions or the functionality of automatic equipment.

A RVLMS channel consists of eight sensors in a probe. A channel is OPERABLE if four or more sensors, two or more of the upper four and two or more of the lower four, are OPERABLE.

21. Containment Area Radiation (high range)

High range Containment Area Radiation is a Type E, Category 1 variable, and is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

BASES

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, plant conditions are such that the likelihood of an event occurring that would require PAM instrumentation is low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added in the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS, even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to monitor an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

Note 2 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 Table 3.3.7-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function, starting from the time the Condition was entered for that Function.

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, 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.

BASES

ACTIONS (continued)

B.1

This Required Action specifies initiation of actions in accordance with Specification 5.6.6, which requires a written report to be submitted to the Nuclear Regulatory Commission. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative Required Actions. This Required Action is appropriate in lieu of a shutdown requirement, given the likelihood of plant conditions that would require information provided by this instrumentation. Also, alternative Required Actions are identified before a loss of functional capability condition occurs.

C.1

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

Condition C is modified by a Note which indicates it is not applicable to hydrogen monitor channels.

D.1

Condition D applies when two hydrogen monitor channels are inoperable. Required Action D.1 requires restoring one hydrogen monitor channel to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable based on the backup capability of the Post Accident Sampling System to monitor the hydrogen concentration for evaluation of core damage and to provide information for operator decisions. Also, it is unlikely that a LOCA (which would cause core damage) would occur during this time.

BASES

ACTIONS (continued)

E.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.7-1. The applicable Condition referenced in the Table is Function dependent. Each time Required Action C.1 or D.1 is not met, and the associated Completion Time has expired, Condition E is entered for that channel and provides for transfer to the appropriate subsequent Condition.

F.1 and F.2

If the Required Action and associated Completion Time of Condition C or D are not met, and Table 3.3.7-1 directs entry into Condition F, the plant must be brought to a MODE in which the requirements of this LCO do not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 30 hours.

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

G.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed and tested. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the plant, but rather to follow the directions of Specification 5.6.6. 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.

BASES

SURVEILLANCE REQUIREMENTS

A Note at the beginning of the Surveillance Requirements specifies that the following SRs apply to each PAM instrumentation Function in Table 3.3.7-1.

SR 3.3.7.1

Performance of the CHANNEL CHECK once every 31 days 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 plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. 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 only verify that they are off scale in the same direction. Off scale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

As indicated in the SR, a CHANNEL CHECK is only required for those channels which are normally energized.

The Frequency of 31 days is based upon plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel during normal operational use of the displays associated with this LCO's required channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.2

A CHANNEL CALIBRATION is performed every 18 months or approximately every refueling. CHANNEL CALIBRATION is typically a complete check of the instrument channel including the sensor. Therefore, this SR is modified by a Note which states that it is not necessary to calibrate neutron detectors because of the difficulty of simulating a meaningful signal. Wide range and source range nuclear instrument channels are not calibrated to indicate the actual power level or the flux in the detector location. The circuitry is adjusted so that wide range and source range readings may be used to determine the approximate reactor flux level for comparative purposes. The Surveillance verifies the channel responds to the measured parameter within the necessary range and accuracy.

For the core exit thermocouples, a CHANNEL CALIBRATION is performed by substituting a known voltage for the thermocouple.

The Frequency is based upon operating experience and consistency with the typical industry refueling cycle and is justified by an 18 month calibration interval for the determination of the magnitude of equipment drift.

REFERENCES

1. FSAR, Appendix 7C, "Regulatory Guide 1.97 Instrumentation"

2. Regulatory Guide 1.97

3. NUREG-0737, Supplement 1

B 3.3 INSTRUMENTATION

B 3.3.8 Alternate Shutdown System

BASES

BACKGROUND

The Alternate Shutdown System provides the control room operator with sufficient instrumentation and controls to maintain the plant 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 plant in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator safety valves or the steam generator atmospheric dump valves can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Primary Coolant System (PCS) from outside the control room allow extended operation in MODE 3.

The Auxiliary Hot Shutdown Panels (C-150/C-150A) are located in the southwest electrical penetration room. These panels are comprised of two enclosures, the main enclosure C-150 and an auxiliary enclosure C-150A. The description below combines these two enclosures into one entity "Panel C-150."

Panel C-150 provides control of the AFW flow control valves and AFW turbine steam supply Valve. Indication of AFW flow, Steam Generator water level , pressurizer pressure, and pressurizer level are provided. See FSAR Section 7.4 (Ref. 1) for operation via Panel C-150.

The instrumentation and equipment controls that are required are listed in Table 3.3.8-1.

Switches, which transfer control or instrument functions from the control room to the C-150 panel, alarm in the control room when the C-150 panel is selected.

APPLICABLE SAFETY ANALYSES

The Alternate Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to maintain the plant in a safe condition in MODE 3.

The criteria governing the design and the specific system requirements of the Alternate Shutdown System are located in 10 CFR 50, Appendix A, GDC 19, and Appendix R (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Alternate Shutdown System has been identified as an important contributor to the reduction of plant risk to accidents and, therefore, satisfies the requirements of Criterion 4 of 10 CFR 50.36(c)(2).

LCO

The Alternate Shutdown System LCO provides the requirements for the OPERABILITY of one channel of the instrumentation and controls necessary to maintain the plant in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Table 3.3.8-1 in the accompanying LCO.

Equipment controls that are required by the alternative dedicated method of maintaining MODE 3 are as follows:

1. AFW flow control valves (CV-0727 and CV-0749); and

2. Turbine-driven AFW pump.

Instrumentation systems displayed on the Auxiliary Hot Shutdown Control Panel are:

1. Source range flux monitor;

2. AFW flow (HIC-0727 and HIC-0749C);

3. Pressurizer pressure;

4. Pressurizer level;

5. SG level and pressure;

6. Primary coolant temperatures (hot and cold legs);

7. Turbine-driven AFW pump low-suction pressure warning light; and

8. SIRW tank level.

A Function of an Alternate Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown Functions are OPERABLE.

BASES

LCO (continued)

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

Table 3.3.8-1 Indication Channel 1, Source Range Nuclear Instrumentation, uses the same detector and preamplifier as the control room channel. Optical isolation is provided between the control room and AHSDP (Alternate Hot Shut Down Panel) portions of the circuit. When the control switches are changed to the "AHSDP" position, the detector and preamplifier is isolated from its normal power supply and connected into the AHSDP power supply.

Table 3.3.8-1 Indication Channels 2 and 12 are provided with their own pressure and level transmitter. The associated circuitry is energized when the AHSDP is energized.

The other Table 3.3.8-1 Indication Channels in Table 3.3.8-1 use a transmitter which also serves normal control room instrumentation. When the control switches are changed to the "AHSDP" (Alternate Hot Shut Down Panel) position, the transmitter is isolated from its normal power supply and circuitry, and connected into the C-150 or C-150A panel circuit; control for AFW flow control valves CV-0727 and CV-0749 is also transferred to C-150. The transfer switches are alarmed in the control room.

APPLICABILITY

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

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the plant is already subcritical and in the condition of reduced PCS energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control become unavailable.

BASES

ACTIONS

A Note has been included that excludes the MODE change restrictions of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS, even though the ACTIONS may eventually require a plant shutdown. This is acceptable due to the low probability of an event requiring this system. The Alternate Shutdown System equipment can generally be repaired during operation without significant risk of spurious trip.

Note 2 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 Table 3.3.8-1. The Completion Time of the inoperable channel 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 the required channels of the Remote Shutdown System are inoperable. This includes any Function listed in Table 3.3.8-1 as well as the control and transfer switches.

Required Action A.1 is to restore the channel to OPERABLE status within 30 days. This allows time to complete repairs on the failed channel. 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 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 4 within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

This SR applies to the startup range neutron flux monitoring channel. The CHANNEL FUNCTIONAL TEST consists of verifying proper response of the channel to the internal test signals, and verification that a detectable signal is available from the detector. After lengthy shutdown periods flux may be below the range of the channel indication. Signal verification with test equipment is acceptable.

The CHANNEL FUNCTIONAL TEST of the startup range neutron flux monitoring channel is performed once within 7 days prior to reactor startup. The Frequency is based on plant operating experience that demonstrates channel failure is rare.

SR 3.3.8.2

SR 3.3.8.2 verifies that each required Alternate Shutdown System transfer switch and control circuit performs its intended function. This verification is performed from AHSDPs C-150 and C-150A and locally, as appropriate. Operation of the equipment from the AHSDPs C-150 and C-150A is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be maintained in MODE 3 from the auxiliary shutdown panel and the local control stations.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience demonstrates that Alternate Shutdown System control channels seldom fail to pass the Surveillance when performed at a Frequency of once every 18 months.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.3

A CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor. The Surveillance verifies that the channel responds to the measured parameter within the necessary range and accuracy.

Performance of a CHANNEL CALIBRATION every 18 months on Functions 1 through 15 ensures that the channels are operating accurately and within specified tolerances. This verification is performed from the AHSDPs and locally, as appropriate. A test of the AFW pump suction pressure alarm (Function 15) is included as part of its CHANNEL CALIBRATION. This will ensure that if the control room becomes inaccessible, the plant can be maintained in MODE 3 from the AHSDPs and local control stations.

The 18 month Frequency is based upon the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience demonstrates that Alternate Shutdown System instrumentation channels seldom fail to pass the Surveillance when performed at a Frequency of once every 18 months. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. Note 1 states that the SR is not required for Functions 16, 17, and 18; Note 2 states that it is not necessary to calibrate neutron detectors because of the difficulty of simulating a meaningful signal. Wide range and source range nuclear instrument channels are not calibrated to indicate the actual power level or the flux in the detector location. The circuitry is adjusted so that wide range and source range readings may be used to determine the approximate reactor flux level for comparative purposes.

REFERENCES

1. FSAR, Section 7.4, "Other Safety Related Protection, Control, and Display Systems"

2. 10 CFR 50, Appendix A, GDC 19 and Appendix R.

B 3.3 INSTRUMENTATION

B 3.3.9 Neutron Flux Monitoring Channels

BASES

BACKGROUND

The neutron flux monitoring channels consist of two combined source range/wide range channels, designated NI-1/3 and NI-2/4. The wide range portions, (NI-3 and NI-4) provide neutron flux power indication from < 1E-7% RTP to > 100% RTP. The source range portions, designated NI-1 and NI-2, provide source range indication over the range of 0.1 to 1E+5 cps.

This LCO addresses MODES 3, 4, and 5. In MODES 1 and 2, the neutron flux monitoring requirements are addressed by LCO 3.3.1, "Reactor Protective System (RPS) Instrumentation."

When the plant is shutdown, both neutron flux monitoring channels must be available to monitor neutron flux. If only one section of a neutron flux monitoring channel (source range or wide range) is functioning, the neutron flux monitoring channel may be considered OPERABLE if it is capable of detecting the existing reactor neutron flux. In this application, the RPS channels need not be OPERABLE since the reactor trip Function is not required. By monitoring neutron flux, loss of SDM caused by boron dilution can be detected as an increase in flux. Two channels must be OPERABLE to provide single failure protection and to facilitate detection of channel failure by providing CHANNEL CHECK capability.

APPLICABLE SAFETY ANALYSES

The neutron flux monitoring channels are necessary to monitor core reactivity changes. They are the primary means for detecting, and triggering operator actions to respond to, reactivity transients initiated from conditions in which the RPS is not required to be OPERABLE. The neutron flux monitoring channel's LCO requirements support compliance with 10 CFR 50, Appendix A, GDC 13 (Ref. 1). The FSAR, Chapters 7 and 14 (Refs. 2 and 3, respectively), describes the specific neutron flux monitoring channel features that are critical to comply with the GDC.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The OPERABILITY of neutron flux monitoring channels is necessary to meet the assumptions of the safety analyses and provide for the detection of reduced SDM.

The neutron flux monitoring channels satisfy Criterion 4 of 10 CFR 50.36(c)(2).

LCO

The LCO on the neutron flux monitoring channels ensures that adequate information is available to verify core reactivity conditions while shut down. The safety function of these instruments is to detect changes in core reactivity such as might occur from an inadvertent boron dilution.

Two neutron flux monitoring channels are required to be OPERABLE. If only one section of a neutron flux monitoring channel (source range or wide range) is functioning, the neutron flux monitoring channel may be considered OPERABLE if it is capable of detecting the existing reactor neutron flux. For example, with the source range count rate indicator functioning properly within its range, and in reasonable agreement with the other source range, a neutron flux monitor channel may be considered OPERABLE even though its wide range indicator is not functioning.

The source range nuclear instrumentation channels, NI-1 and NI-2, provide neutron flux coverage extending an additional one to two decades below the wide range channels for use during refueling, when neutron flux may be extremely low.

This LCO does not require OPERABILITY of the High Startup Rate Trip Function or the Zero Power Mode Bypass Removal Function. Those functions are addressed in LCO 3.3.1, RPS Instrumentation.

APPLICABILITY

In MODES 3, 4, and 5, neutron flux monitoring channels must be OPERABLE to monitor core power for reactivity changes.

In MODES 1 and 2, neutron flux monitoring channels are addressed as part of the RPS in LCO 3.3.1.

The requirements for source range neutron flux monitoring in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation."

BASES

ACTIONS

A.1 and A.2

With one required channel inoperable, it may not be possible to perform a CHANNEL CHECK to verify that the other required channel is OPERABLE. Therefore, with one or more required channels inoperable, the neutron flux power monitoring Function cannot be reliably performed. Consequently, the Required Actions are the same for one required channel inoperable or more than one required channel inoperable. The absence of reliable neutron flux indication makes it difficult to ensure SDM is maintained. Required Action A.1, therefore, requires that all positive reactivity additions that are under operator control, such as boron dilution or PCS temperature changes, be halted immediately, preserving SDM.

SDM must be verified periodically to ensure that it is being maintained. The initial Completion Time of 4 hours and once every 12 hours thereafter to perform SDM verification takes into consideration that Required Action A.1 eliminates many of the means by which SDM can be reduced. These Completion Times are also based on operating experience in performing the Required Actions and the fact that plant conditions will change slowly.

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1

SR 3.3.9.1 is the performance of a CHANNEL CHECK on each required channel every 12 hours. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based upon the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant staff and should be 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 transmitter or the signal processing equipment has drifted outside its limits. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1 (continued)

The Frequency, about once every shift, is based on operating experience that demonstrates the rarity of channel failure. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of displays associated with the LCO required channels.

SR 3.3.9.2

SR 3.3.9.2 is the performance of a CHANNEL CALIBRATION. A CHANNEL CALIBRATION is performed every 18 months. The Surveillance is a complete check and readjustment of the neutron flux channel from the preamplifier input through to the remote indicators.

This SR is modified by a Note which states that it is not necessary to calibrate neutron detectors because of the difficulty of simulating a meaningful signal. Wide range and source range nuclear instrument channels are not calibrated to indicate the actual power level or the flux in the detector location. The circuitry is adjusted so that wide range and source range readings may be used to determine the approximate reactor flux level for comparative purposes.

This LCO does not require the OPERABILITY of the High Startup Rate trip function or the Zero Power Mode Bypass removal function. The OPERABILITY of those functions does not have to be verified during performance of this SR. Those functions are addressed in LCO 3.3.1, RPS Instrumentation.

This Frequency is the same as that employed for the same channels in the other applicable MODES.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13

2. FSAR, Chapter 7

3. FSAR, Chapter 14

B 3.3 INSTRUMENTATION

B 3.3.10 Engineered Safeguards Room Ventilation (ESRV) Instrumentation

BASES

BACKGROUND	This LCO addresses the instrumentation which provides isolation of the ESRV System (Ref. 1). The ESRV Instrumentation high radiation signal provides automatic damper closure, using two radiation monitors. One radiation monitor is located in the ventilation system duct work associated with each of the Engineered Safeguards (ES) pump rooms. Upon detection of high radiation, the ESRV Instrumentation actuates isolation of the associated ES pump room by closing the dampers in the ventilation system inlet and discharge paths. Typically, high radiation would only be expected due to excessive leakage during the recirculation phase of operation following a Loss of Coolant Accident (LOCA). The ESRV System is addressed by LCO 3.7.13, "Engineered Safeguards Room Ventilation (ESRV) Dampers."
APPLICABLE SAFETY ANALYSES	The ESRV Instrumentation isolates the ES pump rooms in the event of high radiation in the pump rooms due to leakage during the recirculation phase. The analysis for a Maximum Hypothetical Accident (MHA) described in FSAR, Section 14.22 (Ref. 2), assumes a reduction factor in the potential radioactive releases from the ES pump rooms due to plateout following automatic isolation. However, no specific value is assumed in the MHA for the actuation of the isolation. The results indicate that the potential MHA offsite doses would be less than 10 CFR 100 guidelines. The ESRV Instrumentation satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2).
LCO	The LCO for the ESRV Instrumentation requires both channels to be OPERABLE to initiate ES pump room isolation when high radiation exceeds the trip setpoint. The ESRV Instrumentation Setpoint is specified as $\leq$ 2.2E+5 cpm. This setpoint is high enough to avoid inadvertent actuation in the event of normal background radiation fluctuations during testing, but low enough to isolate the ES pump room in the event of radiation levels indicative of a LOCA and excessive leakage during recirculation of primary coolant through the ES pump room.

BASES

APPLICABILITY

The ESRV Instrumentation must be OPERABLE in MODES 1, 2, 3, and 4. In these MODES, the potential exists for an accident that could release fission product radioactivity into the primary coolant which could subsequently be released to the environment by leakage from the ES systems which are recirculating the coolant.

While in MODE 5 and in MODE 6, the ESRV 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 10 CFR 100 guidelines.

ACTIONS

The most common causes of channel inoperability are outright failure of loop components or drift of those loop components which is sufficient to exceed the tolerance provided in the plant setpoint analysis. Loop component failures are typically identified by the actuation of alarms due to the channel failing to the "safe" condition, during CHANNEL CHECKS (when the instrument is compared to the redundant channels), or during the CHANNEL FUNCTIONAL TEST (when an automatic component might not respond properly). Typically, the drift of the loop components is found to be small and results in a delay of actuation rather than a total loss of function. Excessive loop component drift would, most likely, be identified during a CHANNEL CHECK (when the instrument is compared to the redundant channels) or during a CHANNEL CALIBRATION (when instrument loop components are checked against reference standards).

A Note has been added to the ACTIONS to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each channel since each channel serves to isolate a different Engineered Safeguards Room. The Completion Times of each inoperable channel will be tracked separately, starting from the time the Condition was entered.

A.1

Condition A addresses the failure of one or both ESRV Instrumentation high radiation monitoring channels. Operation may continue as long as action is immediately initiated to isolate the ESRV System. With the inlet and exhaust dampers closed, the ESRV Instrumentation is no longer required since the potential pathway for radioactivity to escape to the environment has been removed.

BASES

ACTIONS

A.1 (continued)

The Completion Time for this Required Action is commensurate with the importance of maintaining the ES pump room atmosphere isolated from the outside environment when the ES pumps are circulating primary coolant.

SURVEILLANCE REQUIREMENTS

SR 3.3.10.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value.

Significant deviations between the 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 the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Frequency, about once every shift, is based on operating experience that demonstrates the rarity of channel failure. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of the displays associated with the LCO required channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.10.2

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

Any setpoint adjustment must be consistent with the assumptions of the setpoint analyses.

The Frequency of 31 days is based on plant operating experience with regard to channel OPERABILITY, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.

SR 3.3.10.3

CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with the setpoint analysis.

The Frequency is based upon the assumption of an 18 month calibration interval for the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. FSAR, Section 7.4.5.2

2. FSAR, Section 14.22

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Radial Peaking Factors

BASES

BACKGROUND	The Background section of Bases B 3.2.1, "Linear Hear Rate," is applicable to these Bases.
APPLICABLE SAFETY ANALYSES	The Applicable Safety Analyses section of Bases B 3.2.1 is applicable to these Bases. The Power Radial Factors satisfy Criterion 2 of 10 CFR 50.36(c)(2).
LCO	The power distribution LCO limits are based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. The power distribution LCO limits, except T_q, are provided in the COLR. The limitations on F_R^A and F_R^T are provided to ensure that assumptions used in the analysis for establishing DNB margin, LHR limit and the thermal margin/low pressure and variable high power trip setpoints remain valid during operation. Data from the incore detectors are used for determining the measured radial peaking factors.
APPLICABILITY	In MODE 1 with THERMAL POWER > 25% RTP, power distribution must be maintained within the limits assumed in the accident analyses to ensure that fuel damage does not result following an AOO. In MODE 1 with THERMAL POWER ≤ 25% RTP, and in other MODES, this LCO does not apply because there is not sufficient THERMAL POWER to require a limit on the core power distribution, and because ample thermal margin exists to ensure that the fuel integrity is not jeopardized and safety analysis assumptions remain valid.

BASES

ACTIONS

A.1

If one or more Radial Peaking Factors exceed their limits, they must be restored to within their limits as identified in the COLR within 6 hours. Restoration may be either by correcting the source of the peaking or by a conservative reduction in THERMAL POWER. The THERMAL POWER necessary to achieve restoration is typically identified by the equation:

$$P = \left[1-3.33\ ((F_R/F_L)-1)\right] (RTP)$$

Where F_R is the measured value of either F_R^A or F_R^T; and F_L is the corresponding limit provided in the COLR. Operating at or below this power level, P, is typically sufficient to restore the Radial Peaking Factors to within limits. If the reduced power does not restore the Radial Peaking Factor(s) to within limits, further power reduction is necessary. If such power reductions are insufficient to restore the peaking to within limits, Condition B is applicable.

Six hours to restore the Radial Peaking Factor(s) to within their limit(s) is reasonable and ensures that the core does not continue to operate in this condition for an extended period. The 6 hour Completion Time also allows the operator sufficient time for evaluating core conditions and for initiating proper corrective actions.

B.1

If the Required Action and associated Completion Time are not met, THERMAL POWER must be reduced to ≤ 25% RTP. This reduced power level ensures that the core is operating within its thermal limits and places the core in a conservative condition. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reach ≤ 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The periodic Surveillance to determine the calculated F_R^A and F_R^T ensures that the Radial Peaking Factors remain within the range assumed in the analysis throughout the fuel cycle. Determining the measured Radial Peaking Factors using the incore detectors after each fuel loading prior to the reactor exceeding 50% RTP ensures that the core is properly loaded.

Performance of the Surveillance every 31 Effective Full Power Days (EFPD) ensures that unacceptable changes in the Radial Peaking Factors are promptly detected.

REFERENCES

None

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 QUADRANT POWER TILT (T_q)

BASES

BACKGROUND	The Background section for Bases B 3.2.1, "Linear Heat Rate," is applicable to these Bases, with the following addition: The power range monitoring system provides alarms when T_q exceeds predetermined values. The average of the four power range signals is developed by a single "Comparitor Averager." Each power range channel compares its output signal to this average signal. Two channel deviation alarm bistables, set at different levels, are provided in each power range channel. The deviation alarms will annunciate when the associated channel signal is either above or below the average, however, only a signal above the average is of concern with regard to T_q.
APPLICABLE SAFETY ANALYSES	The Applicable Safety Analyses section of Bases B 3.2.1 is applicable to these Bases. The T_q satisfies Criterion 2 of 10 CFR 50.36(c)(2).
LCO	The power distribution LCO limits are based on correlations between power peaking and the measured variables used as inputs to the LHR and DNBR operating limits. The power distribution LCO limits, except T_q, are provided in the COLR. The limits on T_q ensure that assumptions used in the analysis for establishing LHR limits and DNB margin remain valid during operation.
APPLICABILITY	In MODE 1 with THERMAL POWER > 25% RTP, power distribution must be maintained within the limits assumed in accident analysis to ensure that fuel damage does not result following an AOO. In MODE 1 with THERMAL POWER ≤ 25% RTP, and in other MODES, this LCO does not apply because there is not sufficient THERMAL POWER to require a limit on core power distribution, and because ample thermal margin exists to ensure that the fuel integrity is not jeopardized and safety analysis assumptions remain valid.

BASES

ACTIONS

A.1

If the measured T_q is > 0.05, T_q must be restored within 2 hours or F_R^A and F_R^T must be determined to be within the limits of LCO 3.2.2, and determined to be within these limits every 8 hours thereafter, as long as T_q is out of limits. Two hours is sufficient time to allow the operator to reposition control rods, and significant radial xenon redistribution cannot occur within this time. The 8 hour Completion Time ensures changes in F_R^A and F_R^T can be identified before the limits of LCO 3.2.2 are exceeded.

B.1

With the measured T_q > 0.10, power must be reduced to < 50% RTP within 4 hours, and F_R^A and F_R^T must be within their specified limits to ensure that acceptable flux peaking factors are maintained as required by Condition A (which continues to be applicable). Based on operating experience, 4 hours is sufficient time for evaluation of these factors. If F_R^A and F_R^T are within limits, operation may proceed while attempts are made to restore T_q to within its limit. If the tilt is generated due to a control rod misalignment, continued operation at < 50% RTP allows for realignment; if the cause is other than control rod misalignment, continued operation may be necessary to discover the cause of the tilt. Reducing THERMAL POWER to < 50% RTP, and the more frequent measurement of peaking factors required by ACTION A.1, provide conservative protection from potential increased peaking due to xenon redistribution.

C.1

If T_q is > 0.15, or if Required Actions and associated Completion Times are not met, THERMAL POWER must be reduced to ≤ 25% RTP. This requirement ensures that the core is operating within its thermal limits and places the core in a conservative condition. Four hours is a reasonable time to reach 25% RTP in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

QUADRANT POWER TILT (T_q) is determined from excore detector readings which are calibrated using incore detector measurements (Ref. 1). Calibration factors are determined using incore measurements and an incore analysis computer program (Ref. 2). Each power range channel provides alarms if T_q exceeds its limits. Therefore, with all power range channels OPERABLE, this SR only requires verification that the channel deviation alarms do not indicate an excessive T_q. If the Excore Monitoring System T_q deviation alarm monitoring function is inoperable, excore detector readings or symmetric incore detector readings may be used to monitor T_q at 12 hour intervals. The 12 hour Frequency prevents significant xenon redistribution between Surveillances.

REFERENCES

1. FSAR, Section 7.4.2.2

2. FSAR, Section 7.6.2.4

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.1 PCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining PCS 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 DNB related parameters ensure that these parameters, when appropriate measurement uncertainties are applied, will not be less conservative than were assumed in the analyses and thereby provide assurance that the minimum Departure from Nucleate Boiling Ratio (DNBR) will meet the required criteria for each of the transients analyzed.

Another set of limits on DNB related parameters is provided in Safety Limit (SL) 2.1.1, "Reactor Core Safety Limits." The restriction of the SLs prevent overheating of the fuel and cladding that would result in the release of fission products to the primary coolant. The limits of LCO 3.4.1, in combination with other LCOs, are designed to prevent violation of the reactor core SLs.

The LCO limits for minimum and maximum PCS pressures as measured at the pressurizer are consistent with operation within the nominal operating envelope and are bounded by those used as the initial pressures in the analyses.

The LCO limit for maximum PCS cold leg temperature is consistent with operation at steady state power levels and is bounded by those used as the initial temperatures in the analyses.

The LCO limits for minimum PCS flow rate is bounded by those used as the initial flow rates in the analyses. The PCS flow rate is not expected to vary during plant operation with all Primary Coolant Pumps running.

BASES

APPLICABLE SAFETY ANALYSES

The requirements of LCO 3.4.1 represent the initial conditions for DNB DNB limited transients analyzed in the safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will meet the DNBR Safety Limit (SL 2.1.1). This is the acceptance limit for the PCS DNB parameters. Changes to the facility that could impact these parameters must be assessed for their impact on the DNBR criterion. The transients analyzed for include loss of coolant flow events and dropped or stuck control 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, "Regulating Rod Group Position Limits"; LCO 3.2.3, "Quadrant Power Tilt"; and LCO 3.2.4, "AXIAL SHAPE INDEX." The safety analyses are performed over the following range of initial values: PCS pressure 1700 - 2300 psia, core inlet temperature 500-580°F, and a measured reactor vessel inlet coolant flow rate ≥ 352,000 gpm.

The PCS DNB limits satisfy Criterion 2 of 10 CFR 50.36(c)(2).

LCO

This LCO specifies limits on the monitored process of variables PCS pressurizer pressure and PCS cold leg temperature, and the calculated value of PCS total flow rate to ensure that the core operates within the limits assumed for the plant safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

The LCO numerical values for pressure and temperature are given for the measurement location but have not been adjusted for instrument error. Plant specific limits of instrument error are established by the plant staff to meet the operational requirements of this LCO. Instrument errors and the PCS flow rate measurement error are applied to the LCO numerical values in the safety analysis.

BASES

LCO (continued)

LCO 3.4.1.b is modified by a Note which states if the measured primary coolant system flow rate is greater the 150.0 E6 lbm/hr, then the maximum cold leg temperature shall be less than or equal to the T_c derived at 150.0 E6 lbm/hr. The purpose of this Note is to restrict the calculated value of T_c to within the validity limits of the T_c equation. A DNB analysis was performed in a parametric fashion to determine the core inlet temperature as a function of pressure and flow which the minimum DNBR is equal to the DNB correlation safety limit. This analysis includes the following uncertainties and allowances: 2% of rated power for power measurement; ± 0.06 for ASI measurement; ± 22 psi for pressurizer pressure; ± 2°F for inlet temperature; and 3% measurement and 3% bypass for core flow. In addition, transient biases were included in the determination of the allowable reactor inlet temperature. The limits of validity of the T_c equation are:

Pressurizer Pressure ≥ 1800 and ≤ 2200 psia;
PCS Flow Rate ≥ 100.0 E6 and ≤ 150.0 E6 lbm/hr; and
ASI as shown in COLR.

Thus, limiting the maximum allowed T_c to the value derived at 150.0 E6 lbm/hr assures an increase in the margin to DNB for PCS flow rates in excess of 150.0 E6 lbm/hr.

APPLICABILITY

In MODE 1, the limits on PCS pressurizer pressure, PCS cold leg temperature, and PCS flow rate must be maintained during steady state operation in order to ensure that 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 so that DNBR is not a concern.

ACTIONS

A.1

Pressurizer pressure and cold leg temperature are controllable and measurable parameters. PCS flow rate is not a controllable parameter and is not expected to vary during steady state operation. With any of these parameters not within the LCO limits, action must be taken to restore the parameter.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause of the off normal condition, and to restore the readings within limits. The Completion Time is based on plant operating experience.

BASES

ACTIONS (continued)

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds.

Six hours is a reasonable time that permits the plant power to be reduced at an orderly rate without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 and SR 3.4.1.2

The Surveillance for monitoring pressurizer pressure and PCS cold leg temperature is performed using installed instrumentation. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and verify operation is within safety analysis assumptions.

SR 3.4.1.3

Measurement of PCS total flow rate verifies that the actual PCS flow rate is within the bounds of the analyses. This verification may be performed by a calorimetric heat balance or other method.

The Frequency of 18 months reflects the importance of verifying flow after a refueling outage where the core has been altered, which may have caused an alteration of flow resistance. PCS flow rate must also be verified after plugging of each 10 or more steam generator tubes since plugging 10 or more tubes could result in an increase in PCS flow resistance. Plugging less than 10 steam generator tubes will not have a significant impact on PCS flow resistance and, as such, does not require a verification of PCS flow rate.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.3 (continued)

The SR is modified by a Note that states the SR is only required to be performed 31 EFPD after THERMAL POWER is ≥ 90% RTP. The Note is necessary to allow measurement of the flow rate at normal operating conditions at power in MODE 1. The most common, and perhaps accurate, method used to perform the PCS total flow surveillance is by means of a primary to secondary heat balance (calorimetric) with the plant at or near full rated power. The most accurate results for such a test are obtained with the plant at or near full power when differential temperatures measured across the reactor are the greatest. Consequently, the test should not be performed until reaching near full power (i.e., ≥ 90% RTP) conditions. Similarly, test accuracy is also influenced by plant stability. In order for accurate results to be obtained, steady state plant conditions must exist to permit meaningful data to be gathered during the test. Typically, following an extended shutdown the secondary side of the plant will take up to several days to stabilize after power escalation. It is impracticable to perform a primary to secondary heat balance of the precision required for the PCS flow measurement until stabilization has been achieved. Furthermore, an integral part of the PCS flow heat balance involves the use of Ultrasonic Flow Measurement equipment for measuring steam generator feedwater flow. This equipment requires, stable plant operation at or near full power conditions before it can be used. As such, the Surveillance cannot be performed in MODE 2 or below, and will not yield accurate results if performed below 90% RTP.

REFERENCES

1. FSAR, Section 14.1

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.2 PCS Minimum Temperature for Criticality

BASES

BACKGROUND

Establishing the value for the minimum temperature for reactor criticality is based upon considerations for:

a. Operation within the existing instrumentation ranges and accuracies;

b. Operation within the bounds of the existing accident analyses; and

c. Operation with the reactor vessel above its minimum nil ductility reference temperature when the reactor is critical.

The primary coolant moderator temperature coefficient used in core operating and accident analysis is typically defined for the normal operating temperature range (532°F to 570°F). The Reactor Protective System receives inputs from the narrow range hot leg and cold leg temperature instruments, which have a range of 515°F to 615°F. The PCS loop average temperature (T_{ave}) is controlled using inputs of the same range. Nominal T_{ave} for making the reactor critical is 532°F. Safety and operating analyses for lower than 525°F have not been made.

APPLICABLE SAFETY ANALYSES

There are no accident analyses that dictate the minimum temperature for criticality, but existing transient analysis are bounding for operation at low power with cold leg temperatures of 525°F (Ref. 1).

The PCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

The purpose of the LCO is to prevent criticality outside the normal operating regime (532°F to 570°F) and to prevent operation in an unanalyzed condition.

The LCO provides a reasonable distance between the hot zero power value of 532°F and the limit of 525°F. This allows adequate time to trend its approach and take corrective actions prior to exceeding the limit.

BASES

APPLICABILITY

The reactor has been designed and analyzed to be critical in MODES 1 and 2 only and in accordance with this specification. Criticality is not permitted in any other MODE. Therefore, this LCO is applicable in MODE 1, and MODE 2 when $K_{eff} \geq 1.0$.

ACTIONS

A.1

If T_{ave} is below 525°F and cannot be restored in 30 minutes, 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 reflects the ability to perform this action and to maintain the plant within the analyzed range.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

PCS loop average temperature is required to be verified at or above 525°F every 12 hours. The SR to verify PCS loop average temperature every 12 hours takes into account indications and alarms that are continuously available to the operator in the control room.

REFERENCES

1. FSAR, Section 14.1.3

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.3 PCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the PCS 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 PCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

Figures 3.4.3-1 and 3.4.3-2 contain P/T limit curves for heatup, cooldown, and Inservice Leak and Hydrostatic (ISLH) testing, and data for the maximum rate of change of primary coolant temperature. A discussion of the methodology for the development of the P/T curves is provided in Reference 1.

Each P/T limit curve defines an acceptable region for normal operation. The P/T limit curves include an allowance to account for the fact that pressure is measured in the pressurizer rather than at the vessel beltline and to account for primary coolant pump discharge pressure. The use of the curves provides operational limits during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the Primary Coolant Pressure Boundary (PCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply to the vessel.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for material fracture toughness requirements of the PCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the ASME Code, Section III, Appendix G (Ref. 3).

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

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 may alter the location of the tensile stress between the outer and inner walls.

The minimum temperature at which the reactor can be made critical, as required by Reference 2, shall be at least 40°F above the heatup curve or the cooldown curve and not less than the minimum permissible temperature for the ISLH testing. However, the criticality limit is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "PCS Minimum Temperature for Criticality," and LCO 3.1.7, "Special Test Exceptions (STE)."

The consequence of violating the LCO limits is that the PCS has been operated under conditions that can result in brittle failure of the PCPB, 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 PCPB components. The ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) Analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the PCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

The PCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2).

BASES

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the PCS, 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 PCPB components. The consequences depend on several factors, as follows:

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 PCS P/T limits Specification 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.

BASES

APPLICABILITY (continued)

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, "PCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "PCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

The actions of this LCO consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures.

ACTIONS

A.1 and A.2

Operation outside the P/T limits must be corrected so that the PCPB 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 to within limits, an evaluation is required to determine if PCS operation can continue. The evaluation must verify the PCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

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

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.

BASES

ACTIONS

A.1 and A.2 (continued)

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 PCPB 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:

a. The PCS remained in an unacceptable P/T region for an extended period of increased stress; or

b. 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 PCS at reduced pressure and temperature. With reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by placing the plant in MODE 3 within 6 hours and in MODE 5 with PCS pressure < 270 psia within 36 hours.

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

BASES

ACTIONS (continued)

C.1 and C.2

The actions of this LCO, anytime other than in MODE 1, 2, 3, or 4, consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures. Operation outside the P/T limits must be corrected so that the PCPB is returned to a condition that has been verified by stress analyses.

The Completion Time of "immediately" 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 a short period of time in a controlled manner.

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

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

The Completion Time of prior to entering MODE 4 forces the evaluation prior to entering a MODE where temperature and pressure can be significantly increased. The evaluation for a mild violation is possible within several days, but more severe violations may require special, event specific stress analyses or inspections.

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 PCPB integrity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the limits of Figure 3.4.3-1 and Figure 3.4.3-2 is required every 30 minutes when PCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor PCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time. Calculation of the average hourly cooldown rate must consider changes in reactor vessel inlet temperature caused by initiating shutdown cooling, by starting primary coolant pumps with a temperature difference between the steam generator and PCS, or by stopping primary coolant pumps with shutdown cooling in service.

Surveillance for heatup and cooldown operations 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 requires this SR be performed only during PCS heatup and cooldown operations. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. Safety Evaluation for Palisades Nuclear Plant License Amendment No. 163, dated March 2, 1995

2. 10 CFR 50, Appendix G

3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G

4. ASTM E 185-82, July 1982

5. 10 CFR 50, Appendix H

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.4 PCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the PCS 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 PCS 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 plant shutdown.

The PCS configuration for heat transport uses two PCS loops. Each PCS loop contains an SG and two Primary Coolant Pumps (PCPs). A PCP is located in each of the two SG cold legs. The pump flow rate has been sized to provide core heat removal with appropriate margin to Departure from Nucleate Boiling (DNB) during power operation and for anticipated transients originating from power operation. This Specification requires two PCS loops with both PCPs in operation in each loop. The intent of the Specification is to require core heat removal with forced flow during power operation. Specifying two PCS loops provides the minimum necessary paths (two SGs) for heat removal.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the Design Bases Accident (DBA) initial conditions including PCS pressure, PCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the primary coolant forced flow rate, which is represented by the number of PCS loops in service.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on DNB. The transient or accident analysis for the plant has been performed assuming four PCPs are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are of most importance to PCP operation are the Loss of Forced Primary Coolant Flow, Primary Coolant Pump Rotor Seizure and Uncontrolled Control Rod Withdrawal events (Ref. 1).

Steady state DNB analysis had been performed for the four pump combination. The steady state DNB analysis, which generates the pressure and temperature and Safety Limit (i.e., the Departure from Nucleate Boiling Ratio (DNBR) limit), assumes a maximum power level of 112% RTP. This is the design overpower condition for four pump operation. The 112% value is the accident analysis setpoint of the trip and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

PCS Loops - MODES 1 and 2 satisfy Criteria 2 and 3 of 10 CFR 50.36(c)(2).

LCO

The purpose of this LCO is to require adequate forced flow for core heat removal. Flow is represented by having both PCS loops with both PCPs in each loop in operation for removal of heat by the two SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

Each OPERABLE loop consists of two PCPs providing forced flow for heat transport to an SG that is OPERABLE in accordance with the Steam Generator Tube Surveillance Program. SG, and hence PCS loop OPERABILITY with regards to SG water level is ensured by the Reactor Protection System (RPS) in MODES 1 and 2. A reactor trip places the plant in MODE 3 if any SG water level is $\leq$ 25.9% (narrow range) as sensed by the RPS. The minimum level to declare the SG OPERABLE is 25.9% (narrow range).

In MODES 1 and 2, the reactor can be critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all PCS loops are required to be in operation in these MODES to prevent DNB and core damage.

BASES

APPLICABILITY

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, 5, and 6.

Operation in other MODES is covered by:

LCO 3.4.5, "PCS Loops-MODE 3";

LCO 3.4.6, "PCS Loops-MODE 4";

LCO 3.4.7, "PCS Loops-MODE 5, Loops Filled";

LCO 3.4.8, "PCS Loops-MODE 5, Loops Not Filled";

LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation-High Water Level" (MODE 6); and

LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits. It should be noted that the reactor will trip and place the plant in MODE 3 as soon as the RPS senses less than four PCPs operating.

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours of the required number of loops in operation. Verification may include indication of PCS flow, temperature, or pump status, which help to ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

REFERENCES

1. FSAR, Section 14.1

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.5 PCS Loops - MODE 3

BASES

BACKGROUND

The primary function of the primary coolant in MODE 3 is removal of decay heat and transfer of this heat, via the Steam Generators (SGs), to the secondary plant fluid. The secondary function of the primary coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 3, Primary Coolant Pumps (PCPs) are used to provide forced circulation heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single PCS loop with one PCP is sufficient to remove core decay heat. However, two PCS loops are required to be OPERABLE to provide redundant paths for decay heat removal. Any combination of OPERABLE PCPs and OPERABLE PCS loops can be used to fulfill the heat removal function.

Primary coolant natural circulation is not normally used but is sufficient for core cooling. However, natural circulation does not provide turbulent flow conditions. Therefore, boron reduction in natural circulation is prohibited because mixing to obtain a homogeneous concentration in all portions of the PCS cannot be ensured. Any combination of OPERABLE PCPs and OPERABLE PCS loops can be used to fulfill the mixing function.

APPLICABLE SAFETY ANALYSES

Failure to provide heat removal may result in challenges to a fission product barrier. The PCS 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.

PCS Loops - MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The purpose of this LCO is to require two PCS loops to be available for heat removal, thus providing redundancy. The LCO requires the two loops to be OPERABLE with the intent of requiring both SGs to be capable (> -84% water level) of transferring heat from the primary coolant at a controlled rate. Forced primary coolant flow is the required way to transport heat, although natural circulation flow provides adequate removal. A minimum of one running PCP meets the LCO requirement for one loop in operation.

BASES

LCO (continued)

Note 1 permits all PCPs to not be in operation ≤ 1 hour per 8 hour period. This means that natural circulation has been established using the SGs. The Note prohibits boron dilution when forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction. The response of the PCS without the PCPs depends on the core decay heat load and the length of time that the pumps are stopped. As decay heat diminishes, the effects on PCS temperature and pressure diminish. Without cooling by forced flow, higher heat loads will cause the reactor coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (Pressure and Temperature (P/T) limits or Low Temperature Overpressure Protection (LTOP) limits) must be observed and forced flow or heat removal via the SGs must be re-established prior to reaching the pressure limit. The circumstances for stopping the PCPs are to be limited to situations where:

a. Pressure and temperature increases can be maintained well within the allowable pressure (P/T limits and LTOP) and 10°F subcooling limits; or

b. An alternate heat removal path through the SGs is in operation.

In MODE 3, it is sometimes necessary to stop all PCP forced circulation. This is permitted to perform surveillance or startup testing, to perform the transition to and from SDC, or to avoid operation below the PCP minimum net positive suction head limit. The time period is acceptable because natural circulation is adequate for heat removal, or the reactor coolant temperature can be maintained subcooled and boron stratification affecting reactivity control is not expected.

Note 2 requires that one of the following conditions be satisfied before forced circulation (starting the first PCP) may be started:

a. PCS cold leg temperature (T_c) is > 430°F;

b. SG secondary temperature is equal to or less than the reactor inlet temperature (T_c);

c. SG secondary temperature is < 100°F above T_c, and shutdown cooling is isolated from the PCS, and PCS heatup/cooldown rate is ≤ 10°F/hour; or

BASES

LCO (continued)

d. SG secondary temperature is < 100 °F above T_c, and shutdown cooling is isolated from the PCS, and pressurizer level is ≤ 57%.

Satisfying any of the above conditions will preclude a large pressure surge in the PCS when the PCP is started. Energy additions from the steam generators could occur if a PCP was started when the steam generator secondary temperature is significantly above the PCS temperature. The maximum pressurizer level at which credit is taken for having a bubble (57%, which provides about 700 cubic feet of steam space) is based on engineering judgement and verified by LTOP analysis. This level provides the same steam volume to dampen pressure transients as would be available at full power.

An OPERABLE PCS loop consists of any one (of the four) OPERABLE PCP and an SG that is OPERABLE in accordance with the Steam Generator Tube Surveillance Program and has the minimum water level specified in SR 3.4.5.2. A PCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, the heat load is lower than at power; therefore, one PCS loop in operation is adequate for transport and heat removal. A second PCS loop is required to be OPERABLE but is not required to be in operation for redundant heat removal capability.

Operation in other MODES is covered by:

LCO 3.4.4, "PCS Loops-MODES 1 and 2";

LCO 3.4.6, "PCS Loops-MODE 4";

LCO 3.4.7, "PCS Loops-MODE 5, Loops Filled";

LCO 3.4.8, "PCS Loops-MODE 5, Loops Not Filled";

LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation-High Water Level" (MODE 6); and

LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation-Low Water Level" (MODE 6).

BASES

ACTIONS

A.1

If one required PCS loop is inoperable, redundancy for forced flow heat removal is lost. The Required Action is restoration of the required PCS loop to OPERABLE status within a 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.

B.1

If restoration is not possible within 72 hours, the plant must be placed in MODE 4 within 24 hours. In MODE 4, the plant may be placed on the SDC System. The Completion Time of 24 hours is compatible with required operation 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 no PCS loop is in operation, except as provided in Note 1 in the LCO section, all operations involving a reduction of PCS boron concentration must be immediately suspended. This is necessary because boron dilution requires forced circulation for proper homogenization. Action to restore one PCS loop to OPERABLE status and operation shall be initiated immediately and continued until one PCS loop is restored to OPERABLE status and operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required number of PCS loops are in operation. Verification include indication of PCS flow, temperature, and pump status, which help ensure that forced flow is providing heat removal and mixing of the soluble boric acid. The Frequency of 12 hours has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.2

This SR requires verification every 12 hours that the secondary side water level in each SG is ≥ -84% using the wide range level instrumentation. An adequate SG water level is required in order to have a heat sink for removal of the core decay heat from the primary coolant. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within the safety analyses assumptions.

SR 3.4.5.3

Verification that the required PCP is OPERABLE ensures that the single failure criterion is met and that an additional PCS loop can be placed in operation, if needed, to maintain decay heat removal and primary coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required PCP that is not in operation such that the PCP is capable of being started and providing forced PCS flow if needed. Proper breaker alignment and power availability means the breaker for the required PCP is racked-in and electrical power is available to energize the PCP motor. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.6 PCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the primary coolant is the removal of decay heat and transfer of this heat to the Steam Generators (SGs) or Shutdown Cooling (SDC) heat exchangers. The secondary function of the primary coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 4, either Primary Coolant Pumps (PCPs) or SDC trains can be used for coolant circulation. The intent of this LCO is to provide forced flow from any one (of the four) PCP or one SDC train for decay heat removal and transport. The flow provided by one PCP loop or SDC train is adequate for heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

The boron concentration must be uniform throughout the PCS volume to prevent stratification of primary coolant at lower boron concentrations which could result in a reactivity insertion. Sufficient mixing of the primary coolant is assured if one PCP is in operation. PCS circulation is considered in the determination of the time available for mitigation of the inadvertent boron dilution event. By imposing a minimum flow through the reactor core of 2810 gpm, sufficient time is provided for the operator to terminate a boron dilution under asymmetric flow conditions. Due to its system configuration (i.e., no throttle valves) and large volumetric flow rate, a minimum flow rate is not imposed on the PCPs.

PCS Loops - MODE 4 satisfies Criterion 4 of 10 CFR 50.36(c)(2).

LCO

The purpose of this LCO is to require that two loops or trains, PCS or SDC, be OPERABLE in MODE 4 and one of these loops or trains to be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of PCS and SDC System loops. Any one PCS loop in operation, or SDC in operation with a flow ≥ 2810 gpm through the reactor core, provides enough flow to remove the decay heat from the core with forced circulation and provide sufficient mixing of the soluble boric acid. An additional loop or train is required to be OPERABLE to provide redundancy for heat removal.

BASES

LCO (continued)

Note 1 permits all PCPs and SDC pumps to not be in operation ≤ 1 hour per 8 hour period. The Note prohibits boron dilution when forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction. The response of the PCS without the PCPs or SDC pumps depends on the core decay heat load and the length of time that the pumps are stopped. As decay heat diminishes, the effects on PCS temperature and pressure diminish. Without cooling by forced flow, higher heat loads will cause the primary coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (Pressure and Temperature (P/T) limits or Low Temperature Overpressure Protection (LTOP) limits) must be observed and forced SDC flow or heat removal via the SGs must be re-established prior to reaching the pressure limit. The circumstances for stopping both PCPs or SDC pumps are to be limited to situations where:

a. Pressure and temperature increases can be maintained well within the allowable pressure (P/T limits and LTOP) and 10°F subcooling limits; or

b. An alternate heat removal path through the SGs is in operation.

In MODE 4, it is sometimes necessary to stop all PCPs or SDC forced circulation. This is permitted to change operation from one SDC train to the other, perform surveillance or startup testing, perform the transition to and from SDC, or to avoid operation below the PCP minimum net positive suction head limit. The time period is acceptable because natural circulation is acceptable for decay heat removal, the primary coolant temperature can be maintained subcooled, and boron stratification affecting reactivity control is not expected.

Note 2 requires that one of the following conditions be satisfied before forced circulation (starting the first PCP) may be started:

a. SG secondary temperature is ≤ T_c;

b. SG secondary temperature is < 100°F above T_c, and shutdown cooling is isolated from the PCS, and PCS heatup/cooldown rate is ≤ 10°F/hour; or

c. SG secondary temperature is < 100°F above T_c, and shutdown cooling is isolated from the PCS, and pressurizer level is ≤ 57%.

BASES

LCO (continued)

Satisfying any of the above conditions will preclude a large pressure surge in the PCS when the PCP is started. Energy additions from the steam generators could occur if a PCP was started when the steam generator secondary temperature is significantly above the PCS temperature. The maximum pressurizer level at which credit is taken for having a bubble (57%, which provides about 700 cubic feet of steam space) is based on engineering judgement and verified by LTOP analysis. This level provides the same steam volume to dampen pressure transients as would be available at full power.

Note 3 specifies a limitation on the simultaneous operation of primary coolant pumps P-50A and P-50B which allows the pressure limits in LCO 3.4.3, "PCS Pressure and Temperature Limits," and LCO 3.4.12, "Low Temperature Overpressure Protection System," to be higher than they would be without this limit. This is because the pressure in the reactor vessel downcomer region when primary coolant pumps P-50A and P-50B are operated simultaneously is higher than the pressure for other two primary coolant pump combinations.

An OPERABLE PCS loop consists of any one (of the four) OPERABLE PCP and an SG that is OPERABLE in accordance with the Steam Generator Tube Surveillance Program and has the minimum water level specified in SR 3.4.6.2.

Similarly, for the SDC System, an OPERABLE SDC train is composed of the OPERABLE SDC pump(s) and an OPERABLE SDC heat exchanger. PCPs are OPERABLE if they are capable of being powered and are able to provide flow if required. SDC pumps are OPERABLE if they are capable of being powered and able to provide forced flow through the reactor core at a flow rate ≥ 2810 gpm.

BASES

APPLICABILITY

In MODE 4, this LCO applies because it is possible to remove core decay heat and to provide proper boron mixing with either the PCS loops and SGs, or the SDC System.

Operation in other MODES is covered by:

LCO 3.4.4, "PCS Loops-MODES 1 and 2";

LCO 3.4.5, "PCS Loops-MODE 3";

LCO 3.4.7, "PCS Loops-MODE 5, Loops Filled";

LCO 3.4.8, "PCS Loops-MODE 5, Loops Not Filled";

LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation-High Water Level" (MODE 6); and

LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1

If only one PCS loop is OPERABLE and in operation with no OPERABLE SDC trains, redundancy for heat removal is lost. Action must be initiated immediately to restore a second PCS loop or one SDC train to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for decay heat removal.

B.1

If only one SDC train is OPERABLE and in operation with no OPERABLE PCS loops, redundancy for heat removal is lost. The plant must be placed in MODE 5 within the next 24 hours. Placing the plant in MODE 5 is a conservative action with regard to decay heat removal. With only one SDC train OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining SDC train, it would be safer to initiate that loss from MODE 5 (≤ 200°F) rather than MODE 4 (> 200°F to < 300°F). The Completion Time of 24 hours is reasonable, based on operating experience, to reach MODE 5 from MODE 4, with only one SDC train operating, in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

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

If no PCS loops or SDC trains are OPERABLE, or no PCS loop is in operation and the SDC flow through the reactor core is < 2810 gpm, except during conditions permitted by Note 1 in the LCO section, all operations involving reduction of PCS boron concentration must be suspended. Action to restore one PCS loop or SDC train to OPERABLE status and operation shall be initiated immediately and continue until one loop or train is restored to operation and flow through the reactor core is restored to ≥ 2810 gpm. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one required loop or train is in operation. This ensures forced flow is providing heat removal and mixing of the soluble boric acid. Verification may include flow rate (SDC only), or indication of flow, temperature, or pump status for the PCP. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess PCS loop/SDC train status. In addition, control room indication and alarms will normally indicate loop/train status.

SR 3.4.6.2

This SR requires verification every 12 hours of secondary side water level in the required SG(s) ≥ -84% using the wide range level instrumentation. An adequate SG water level is required in order to have a heat sink for removal of the core decay heat from the primary coolant. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify SG status.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional PCS loop or SDC train can be placed in operation, if needed to maintain decay heat removal and primary coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump that is not in operation such that the pump is capable of being started and providing forced PCS flow if needed. Proper breaker alignment and power availability means the breaker for the required pump is racked-in and electrical power is available to energize the pump motor. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.7 PCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the PCS loops filled, the primary function of the primary coolant is the removal of decay heat and transfer this heat either to the Steam Generator (SG) secondary side coolant via natural circulation (Ref. 1) or the Shutdown Cooling (SDC) heat exchangers. While the principal means for decay heat removal is via the SDC System, the SGs via natural circulation are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary side water. If heatup of the PCS were to continue, the contained inventory of the SGs would be available to remove decay heat by producing steam. As long as the SG secondary side water is at a lower temperature than the primary coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the primary coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with PCS loops filled, the SDC trains are the principal means for decay heat removal. The number of trains in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one SDC train for decay heat removal and transport. The flow provided by one SDC train 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 decay heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an SDC train that must be OPERABLE and in operation. The second path can be another OPERABLE SDC train, or through the SGs, via natural circulation each having an adequate water level. "Loops filled" means the PCS loops are intact, not blocked by dams, and totally filled with coolant.

BASES

APPLICABLE SAFETY ANALYSES

The boron concentration must be uniform throughout the PCS volume to prevent stratification of primary coolant at lower boron concentrations which could result in a reactivity insertion. Sufficient mixing of the primary coolant is assured if one SDC pump is in operation. PCS circulation is considered in the determination of the time available for mitigation of the inadvertent boron dilution event. By imposing a minimum flow through the reactor core of 2810 gpm, sufficient time is provided for the operator to terminate a boron dilution under asymmetric flow conditions.

PCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2).

LCO

The purpose of this LCO is to require one SDC train be OPERABLE and in operation with either an additional SDC train OPERABLE or the secondary side water level of each SG ≥ -84%. SDC in operation with a flow through the reactor core ≥ 2810 gpm, provides enough flow to remove the decay heat from the core with forced circulation and provide sufficient mixing of the soluble boric acid. The second SDC train is normally maintained OPERABLE as a backup to the operating SDC train to provide redundant paths for decay heat removal. However, if the standby SDC train is not OPERABLE, a sufficient alternate method to provide redundant paths for decay heat removal is two SGs with their secondary side water levels ≥ -84%. Should the operating SDC train fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all SDC pumps to not be in operation ≤ 1 hour per 8 hour period. The Note prohibits boron dilution when forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction. The response of the PCS without the SDC pumps depends on the core decay heat load and the length of time that the pumps are stopped. As decay heat diminishes, the effects on PCS temperature and pressure diminish. Without cooling by forced flow, higher heat loads will cause the primary coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (Pressure and Temperature (P/T) limits or Low Temperature Overpressure Protection (LTOP) limits) must be observed and forced SDC flow or heat removal via the SGs must be re-established prior to reaching the pressure limit.

BASES

LCO (continued)

In MODE 5 with loops filled, it is sometimes necessary to stop all SDC forced circulation. This is permitted to change operation from one SDC train to the other, perform surveillance or startup testing, perform the transition to and from the SDC, or to avoid operation below the PCP minimum net positive suction head limit. The time period is acceptable because natural circulation is acceptable for decay heat removal, the primary coolant temperature can be maintained subcooled, and boron stratification affecting reactivity control is not expected.

Note 2 allows both SDC trains to be inoperable for a period of up to 2 hours provided that one SDC train is in operation providing the required flow, the core outlet temperature is at least 10°F below the corresponding saturation temperature, and each SG secondary water level is ≥ 84%. This permits periodic surveillance tests or maintenance to be performed on the inoperable trains during the only time when such evolutions are safe and possible.

Note 3 requires that one of the following conditions be satisfied before forced circulation (starting the first PCP) may be started:

a. SG secondary temperature is equal to or less than the reactor inlet temperature (T_c);

b. SG secondary temperature is < 100°F above T_c, and shutdown cooling is isolated from the PCS, and PCS heatup/cooldown rate is ≤ 10°F/hour; or

c. SG secondary temperature is < 100°F above T_c, and shutdown cooling is isolated from the PCS, and pressurizer level is ≤ 57%.

Satisfying any of the above conditions will preclude a large pressure surge in the PCS when the PCP is started. Energy additions from the steam generators could occur if a PCP was started when the steam generator secondary temperature is significantly above the PCS temperature. The maximum pressurizer level at which credit is taken for having a bubble (57%, which provides about 700 cubic feet of steam space) is based on engineering judgement and verified by LTOP analysis. This level provides the same steam volume to dampen pressure transients as would be available at full power.

Note 4 specifies a limitation on the simultaneous operation of primary coolant pumps P-50A and P-50B which allows the pressure limits in LCO 3.4.3, "PCS Pressure and Temperature Limits," and LCO 3.4.12, "Low Temperature Overpressure Protection System," to be higher than they would be without this limit.

BASES

LCO (continued)

Note 5 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting SDC trains to not be in operation when at least one PCP is in operation. This Note provides for the transition to MODE 4 where a PCP is permitted to be in operation and replaces the PCS circulation function provided by the SDC trains.

An OPERABLE SDC train is composed of an OPERABLE SDC pump and an OPERABLE SDC heat exchanger. SDC pumps are OPERABLE if they are capable of being powered and are able to provide forced flow through the reactor core at a flow rate ≥ 2810 gpm if required.

An SG can perform as a heat sink via natural circulation when it has the minimum water level specified in SR 3.4.7.2 and is OPERABLE in accordance with the SG Tube Surveillance Program.

APPLICABILITY

In MODE 5 with PCS loops filled, this LCO requires forced circulation to remove decay heat from the core and to provide proper boron mixing. One SDC train provides sufficient circulation for these purposes.

Operation in other MODES is covered by:

LCO 3.4.4, "PCS Loops-MODES 1 and 2";

LCO 3.4.5, "PCS Loops-MODE 3";

LCO 3.4.6, "PCS Loops-MODE 4";

LCO 3.4.8, "PCS Loops-MODE 5, Loops Not Filled";

LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation-High Water Level" (MODE 6); and

LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation-Low Water Level" (MODE 6).

BASES

ACTIONS

A.1 and A.2

If one SDC train is inoperable and any SG has a secondary side water level < -84%, redundancy for heat removal is lost. Action must be initiated immediately to restore a second SDC train to OPERABLE status or to restore the water level in the required SGs. Either Required Action A.1 or Required Action A.2 will restore redundant decay heat removal paths. The immediate Completion Times reflect the importance of maintaining the availability of two paths for decay heat removal.

B.1 and B.2

If no SDC trains are OPERABLE or SDC flow through the reactor core is < 2810 gpm, except as permitted in Note 1, all operations involving the reduction of PCS boron concentration must be suspended. Action to restore one SDC train to OPERABLE status and operation shall be initiated immediately and continue until one train is restored to operation and flow through the reactor core is restored to ≥ 2810 gpm. Boron dilution requires forced circulation for proper mixing and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that one SDC train is in operation. Verification of the required flow rate ensures forced flow is providing heat removal and mixing of the soluble boric acid. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess SDC train status. In addition, control room indication and alarms will normally indicate train status.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.2

This SR requires verification every 12 hours of secondary side water level in the required SGs ≥ -84% using the wide range level instrumentation. An adequate SG water level is required in order to have a heat sink for removal of the core decay heat from the primary coolant. The Surveillance is required to be performed when the LCO requirement is being met by use of the SGs. If both SDC trains are OPERABLE, this SR is not needed. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation and verify SG status.

SR 3.4.7.3

Verification that the second SDC train is OPERABLE ensures that redundant paths for decay heat removal are available. The requirement also ensures that the additional train can be placed in operation, if needed, to maintain decay heat removal and primary coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump that is not in operation such that the SDC pump is capable of being started and providing forced PCS flow if needed. Proper breaker alignment and power availability means the breaker for the required SDC pump is racked-in and electrical power is available to energize the SDC pump motor. The Surveillance is required to be performed when the LCO requirement is being met by one of two SDC trains, e.g., both SGs have < -84% water level. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation"

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.8 PCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the PCS loops not filled, the primary function of the primary coolant is the removal of decay heat and transfer of this heat to the Shutdown Cooling (SDC) heat exchangers. The Steam Generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the primary coolant is to act as a carrier for the soluble neutron poison, boric acid. A loop is considered "not filled" if it has been drained so air has entered the loop which has not yet been removed.

In MODE 5 with loops not filled, only the SDC System can be used for coolant circulation. The number of trains in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one SDC train for decay heat removal and transport and to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

The boron concentration must be uniform throughout the PCS volume to prevent stratification of primary coolant at lower boron concentrations which could result in a reactivity insertion. Sufficient mixing of the primary coolant is assured if one SDC pump is in operation. PCS circulation is considered in the determination of the time available for mitigation of the inadvertent boron dilution event. By imposing a minimum flow through the reactor core of ≥ 2810 gpm, or a minimum flow through the reactor core ≥ 650 gpm with two of the three charging pumps incapable of reducing the boron concentration in the PCS below the minimum value necessary to maintain the required SHUTDOWN MARGIN, sufficient time is provided for the operator to terminate a boron dilution under asymmetric flow conditions.

PCS loops - MODE 5 (Loops Not Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2).

BASES

LCO

The purpose of this LCO is to require a minimum of two SDC trains be OPERABLE and one of these trains be in operation. SDC in operation with a flow rate through the reactor core of ≥ 2810 gpm, or with a flow rate through the reactor core of ≥ 650 gpm with two of the three charging pumps incapable of reducing the boron concentration in the PCS below the minimum value necessary to maintain the required SHUTDOWN MARGIN, provides enough flow to remove the decay heat from the core with forced circulation and provide sufficient mixing of the soluble boric acid. The restriction on charging pump operations only applies to those cases where the potential exists to reduce the PCS boron concentration below minimum the boron concentration necessary to maintain the required SHUTDOWN MARGIN. It is not the intent of this LCO to restrict charging pump operations when the source of water to the pump suction is greater than or equal to the minimum boron concentration necessary to maintain the required SHUTDOWN MARGIN. An additional SDC train is required to be OPERABLE to meet the single failure criterion.

Note 1 permits all SDC pumps to not be in operation for ≤ 1 hour. The Note prohibits boron dilution when forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble may form and possibly cause a flow obstruction. Operations which could drain the PCS and thereby cause a loss of, or failure to regain SDC capability are also prohibited.

In MODE 5 with loops not filled, it is sometimes necessary to stop all SDC forced circulation. This is permitted to change operation from one SDC train to the other, and to perform surveillance or startup testing. The time period is acceptable because the primary coolant will be maintained subcooled, and boron stratification affecting reactivity control is not expected.

Note 2 allows one SDC train to be inoperable for a period of 2 hours provided that the other train is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable train during the only time when these tests are safe and possible.

BASES

LCO (continued)

An OPERABLE SDC train is composed of an OPERABLE SDC pump and an OPERABLE SDC heat exchanger. SDC pumps are OPERABLE if they are capable of being powered and are able to provide forced flow through the reactor core at a flow rate of ≥ 2810 gpm, or at a flow rate of ≥ 650 gpm with two of the three charging pumps incapable of reducing the boron concentration in the PCS below the minimum value necessary to maintain the required SHUTDOWN MARGIN.

APPLICABILITY

In MODE 5 with PCS loops not filled, this LCO requires forced circulation to remove decay heat from the core and to provide proper boron mixing. One SDC train provides sufficient circulation for these purposes.

Operation in other MODES is covered by:

LCO 3.4.4, "PCS Loops-MODES 1 and 2";

LCO 3.4.5, "PCS Loops-MODE 3";

LCO 3.4.6, "PCS Loops-MODE 4";

LCO 3.4.7, "PCS Loops-MODE 5, Loops Filled";

LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation-High Water Level" (MODE 6); and

LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1

If one SDC train is inoperable, redundancy for heat removal is lost. Action must be initiated immediately to restore a second train to OPERABLE status. The Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

BASES

ACTIONS (continued)

B.1 and B.2

If no SDC trains are OPERABLE or SDC flow through the reactor core is not within limits, except as provided in Note 1, all operations involving the reduction of PCS boron concentration must be suspended. Action to restore one SDC train to OPERABLE status and operation shall be initiated immediately and continue until one train is restored to operation and flow through the reactor core is restored to within limits. Boron dilution requires forced circulation for proper mixing and the margin to criticality must not be reduced in this type of operation. The immediate Completion Time reflects the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1 and SR 3.4.8.2

These SRs require verification every 12 hours that one SDC train is in operation. Verification of the required flow rate ensures forced circulation is providing heat removal and mixing of the soluble boric acid. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess SDC train status. In addition, control room indications and alarms will normally indicate train status.

SR 3.4.8.1 and SR 3.4.8.2 are each modified by a Note to indicate the SR is only required to be met when complying with the applicable portion of the LCO. Therefore, it is only necessary to perform either SR 3.4.8.1, or SR 3.4.8.2 based on the method of compliance with the LCO.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.3

This SR requires verification every 12 hours that two of the three charging pumps are incapable of reducing the boron concentration in the PCS below the minimum value necessary to maintain the required SHUTDOWN MARGIN. Making the charging pumps incapable reducing the boron concentration in the PCS may be accomplished by electrically disabling the pump motors, blocking potential dilution sources to the pump suction, or by isolating the pumps discharge flow path to the PCS. Verification may include visual inspection of the pumps configuration (e.g., pump breaker position or valve alignment), or the use of other administrative controls. The 12 hour Frequency is based on engineering judgement considering operating practice, administrative control available, and the unlikeness of inadvertently aligning a charging pump for PCS injection during this period.

SR 3.4.8.3 is modified by a Note to indicate the SR is only required to be met when complying with LCO 3.4.8.b. When SDC flow through the reactor core is ≥ 2810 gpm, there is no restriction on charging pump operation.

SR 3.4.8.4

Verification that the required number of trains are OPERABLE ensures that redundant paths for heat removal are available and that additional trains can be placed in operation, if needed, to maintain decay heat removal and primary coolant circulation. Verification is performed by verifying proper breaker alignment and indicated power available to the required pump that is not in operation such that the SDC pump is capable of being started and providing forced PCS flow if needed. Proper breaker alignment and power availability means the breaker for the required SDC pump is racked-in and electrical power is available to energize the SDC pump motor. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None

B 3.4 PRIMARY COOLANT SYSTEMS (PCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the PCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the PCS. Key functions include maintaining required primary system pressure during steady state operation and limiting the pressure changes caused by primary coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, required heaters capacity, and the emergency power supply to the heaters powered from electrical bus 1E. Pressurizer safety valves and pressurizer Power Operated Relief Valves (PORVs) are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The maximum water level limit has been established to ensure that a liquid to vapor interface exists to permit PCS pressure control, using the sprays and heaters during normal operation and proper pressure response for anticipated design basis transients. The water level limit serves two purposes:

a. Pressure control during normal operation maintains subcooled reactor coolant in the loops and thus in the preferred state for heat transport; and

b. By restricting the level to a maximum, expected transient primary coolant volume increases (pressurizer insurge) will not cause excessive level changes that could result in degraded ability for pressure control.

The maximum water level limit permits pressure control equipment to function as designed. The limit preserves the steam space during normal operation, thus, both sprays and heaters can operate to maintain the design operating pressure. The level limit also prevents filling the pressurizer (water solid) for anticipated design basis transients, thus ensuring that pressure relief devices (PORVs or pressurizer safety valves) can control pressure by steam relief rather than water relief. If the level limits were exceeded prior to a transient that creates a large pressurizer insurge volume leading to water relief, the maximum PCS pressure might exceed the Safety Limit of 2750 psia.

BASES

BACKGROUND (continued)

The requirement to have pressurizer heaters ensures that PCS pressure can be maintained. The pressurizer heaters maintain PCS pressure to keep the primary coolant subcooled. Inability to control PCS pressure during natural circulation flow could result in loss of single phase flow and decreased capability to remove core decay heat.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. 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 noncondensable gases normally present.

Safety analyses presented in the FSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the PCS is operating at normal pressure.

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, "Clarification of TMI Action Plan Requirements," is the reason for their inclusion. The intent is to keep the primary coolant in a subcooled condition with natural circulation at hot, high pressure conditions for an undefined, but extended, time period after a loss of offsite power. While a loss of offsite power is a coincident occurrence assumed in the accident analyses, maintaining hot, high pressure conditions over an extended time period is not evaluated in the accident analyses.

The pressurizer satisfies Criterion 2 (for pressurizer water level) and Criterion 4 (for pressurizer heaters) of 10 CFR 50.36(c)(2).

BASES

LCO

The LCO requirement for the pressurizer to be OPERABLE with water level < 62.8% (hot full power pressurizer high level alarm setpoint) ensures that a steam bubble exists. Limiting the maximum operating water level preserves the steam space for pressure control. The LCO has been established to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions. During a plant heatup, the PCS is generally water solid in the lower temperature range of MODE 3. Therefore, LCO 3.4.9.a has been modified by a Note which states that the pressurizer water level limit does not apply in MODE 3 until after a bubble has been established in the pressurizer and the pressurizer water level has been lowered to its normal operating band. The intent of this Note is to allow entry into the mode of Applicability during a plant heatup when the pressurizer water level is above the limit specified in the LCO. Once the normal pressurizer water level is established, compliance with the LCO must be met without reliance on the Note.

The LCO requires ≥ 375 kW of pressurizer heater capacity available from electrical bus 1D, and ≥ 375 kW of pressurizer heater capacity available from electrical bus 1E with the capability of being powered from an emergency power supply. In the event of a loss of offsite power, one half of the required heater capacity is normally connected to engineered safeguards bus 1D and can be manually controlled via a hand switch in the control room. This would provide sufficient heater capacity to establish and maintain natural circulation in a hot standby condition. To provide a redundant source of heater capacity should bus 1D become unavailable, methods and procedures have been established for manually connecting the required pressurizer heaters capacity, normally fed from electrical bus 1E, to engineered safeguards electrical bus 1C via a jumper cable. The amount of time required to make this connection (less than five hours) has been evaluated to assure that a 20°F subcooling margin, due to pressure decay, is not exceeded (Ref. 2).

The value of 375 kW is derived from the use of 30 heaters rated at approximately 12.5 kW each. The actual amount needed to maintain pressure is dependent on the ambient heat losses.

BASES

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on PCS temperature resulting in the greatest effect on pressurizer level and PCS pressure control. Thus, the Applicability has been designated for MODES 1 and 2. The Applicability is also provided for MODE 3. The purpose is to prevent water solid PCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation. Although the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," ensures overpressure protection is provided in MODE 3 when the PCS cold leg temperature is < 430°F, the Applicability for the pressurizer is all inclusive of MODE 3 since the pressurizer heaters are required in all of MODE 3 to support plant operations. In MODES 4, 5, and 6, the pressurizer is no longer required and overpressure protection is provided by LTOP components specified in LCO 3.4.12.

In MODES 1, 2, and 3, there is the need to maintain the availability of pressurizer heaters capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES gives the greatest demand for maintaining the PCS 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 Shutdown Cooling System is in service and therefore the LCO is not applicable.

ACTIONS

A.1 and A.2

With pressurizer water level not within the limit, action must be taken to restore the plant to operation within the bounds of the safety analyses. To achieve this status, the plant must be brought to MODE 3, with the reactor trippped, within 6 hours and to MODE 4 within 30 hours. This takes the plant out of the applicable MODES and restores the plant to operation within the bounds of the safety analyses.

Six hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Further pressure and temperature reduction to MODE 4 brings the plant to a MODE where the LCO is not applicable. The 30 hour time to reach the nonapplicable MODE is reasonable based on operating experience for that evolution.

BASES

ACTIONS (continued)

B.1

If < 375 kW of pressurizer heater capacity is available from either electrical bus 1D or electrical bus 1E, or the pressurizer heaters from electrical bus 1E are not capable of being powered from an emergency power supply, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering that a demand caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using the remaining available pressurizer heaters.

C.1 and C.2

If the required pressurizer heaters cannot be restored to an OPERABLE status within 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 30 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging safety systems. Similarly, the Completion Time of 30 hours is reasonable, based on operating experience, to reach MODE 4 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR ensures that during steady state operation, pressurizer water 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. SR 3.4.9.1 is modified by a Note which states that verification of the pressurizer water level is not required to be met until 1 hour after a bubble has been established in the pressurizer and the pressurizer water level has been lowered to its normal operating band. The intent of this Note is to prevent an SR 3.0.4 conflict by delaying the performance of this SR until after the water level in the pressurizer is within its normal operating band following a plant heatup. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess the level for any deviation and verify that operation is within safety analyses assumptions. Alarms are also available for early detection of abnormal level indications.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 capacity of the associated pressurizer heaters are verified to be ≥ 375 kW. (This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance.) The Frequency of 18 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

SR 3.4.9.3

This SR only applies to the pressurizer heaters normally powered from electrical bus 1E since the pressurizer heaters powered from bus 1D are permanently connected to the engineered safeguards electrical system.

This SR confirms that the pressurizer heaters normally fed from electrical bus 1E are capable of being powered from electrical bus 1C by use of a jumper cable. It is not the intent of this SR to physically install the jumper cable, but to verify the necessary components are available for installation and to ensure the procedures and methods used to install the jumper cable are current. The Frequency of 18 months is based on engineering judgement and is considered acceptable when considering the design reliability of the equipment (the jumper cable is left permanently in place and dedicated to providing the emergency feed function only), and administrative control which govern configuration management and changes to plant procedures.

REFERENCES

1. FSAR, Chapter 14

2. FSAR, Section 4.3.7

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The purpose of the three spring loaded pressurizer safety valves is to provide PCS overpressure protection. Operating in conjunction with the Reactor Protection System, three valves are used to ensure that the Safety Limit (SL) of 2750 psia is not exceeded for analyzed transients during operation in MODES 1 and 2 and portions of MODE 3. For the remainder of MODE 3, MODE 4, MODE 5, and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and the LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The self actuated pressurizer safety valves are designed in accordance with the requirements set forth in the American Society of Mechanical Engineering (ASME), Boiler and Pressure Vessel Code, Section III (Ref. 1). The required lift settings are given in Table 3.4.10-1 in the accompanying technical specification. The safety valves discharge steam from the pressurizer to a quench tank located in the containment. The discharge flow is indicated by an increase in temperature downstream of the safety valves, acoustic monitors, and by an increase in the quench tank temperature and level.

The lift settings listed in Table 3.4.10-1 correspond to ambient conditions of the valves at nominal operating temperature and pressure. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the PCS pressure will be limited to 110% of design pressure. The consequences of exceeding the ASME pressure limit (Ref. 1) could include damage to PCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

BASES

APPLICABLE SAFETY ANALYSES

All accident analyses in the FSAR that require safety valve actuation assume operation of one or more pressurizer safety valves to limit increasing primary coolant pressure. The overpressure protection analysis assumes that the valves open at the high range of the lift setting including the allowable tolerance. The Loss of External Electrical Load incident and Loss of Normal Feedwater Flow incident are the two safety analyses events which rely on the pressurizer safety valves to mitigate an overpressurization of the PCS. The pressurizer safety valves must also accommodate pressurizer in surges that could occur from a Loss of Forced Primary Coolant Flow incident, and a Primary Pump Rotor Seizure incident. Single failure of a safety valve is neither assumed in the accident analysis nor required to be addressed by the ASME Code. Compliance with this specification is required to ensure that the accident analysis and design basis calculations remain valid.

The pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The three pressurizer safety valves are set to open near the PCS design pressure (2500 psia) and within the ASME specified tolerance to avoid exceeding the maximum PCS design pressure SL, to maintain accident analysis assumptions, and to comply with ASME Code requirements. The nominal lift settings values listed in Table 3.4.10-1, plus an allowable tolerance of ± 3%, establish the acceptable "as-found" pressure band for determining valve OPERABILITY. Following valve testing, an as-left tolerance of ± 1% of the lift settings is imposed by SR 3.4.10.1 to account for setpoint drift during the surveillance interval. The limit protected by this specification is the Primary Coolant Pressure Boundary (PCPB) SL of 110% of design pressure. The inoperability of any valve 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 PCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

BASES

APPLICABILITY

In MODES 1 and 2, and portions of MODE 3 above the LTOP temperature, OPERABILITY of three valves is required because the combined capacity is required to keep primary coolant pressure below 110% of its design value during certain accidents. Portions of MODE 3 are conservatively included, although the listed accidents may not require three safety valves for protection.

The LCO is not applicable in MODE 3 when any PCS cold leg temperatures are < 430°F and MODES 4 and 5 because LTOP protection is provided. Overpressure protection is not required in MODE 6 with the reactor vessel head removed.

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 PCS overpressure protection system. An inoperable safety valve coincident with an PCS overpressure event could challenge the integrity of the PCPB.

B.1 and B.2

If the Required Action 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 at least one PCS cold leg temperature reduced to below 430°F within 12 hours. The 6 hours allowed is reasonable, based on operating experience, to reach MODE 3 from full power without challenging plant systems. Similarly, the 12 hours allowed is reasonable, based on operating experience, to reduce any PCS cold leg temperature < 430°F without challenging plant systems. Below 430°F, overpressure protection is provided by LTOP. The change from MODE 1, 2, or 3 to MODE 3 with any PCS cold leg temperature < 430°F reduces the PCS 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 1), which provides the activities and the Frequency necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint tolerance is ± 3% for OPERABILITY; however, the valves are reset to within a tolerance of ± 1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III, Section XI

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

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 solenoid-pilot operated relief valves which, when placed in the "Auto" position, automatically open at a specific set pressure when the pressurizer pressure increases and is automatically closed on decreasing pressure. The PORV may also be manually operated using controls installed in the control room.

A motor operated, normally closed, block valve is installed between the pressurizer and each PORV. The function of the block valve is to isolate the PORV. Block valve closure is accomplished manually using controls in the control room and may be used to isolate a leaking PORV to permit continued power operation. Most importantly, the block valve is used to isolate a stuck open PORV to isolate the resulting Loss Of Coolant Accident (LOCA). Closure terminates the PCS depressurization and coolant inventory loss.

The PORV, its block valve, and their respective controls are powered from safety class power supplies. Power supplies for the PORV are separate from those for the block valve. Power supply requirements are defined in NUREG-0737, Item II.G.1.

The primary purpose of this LCO is to ensure that the PORV and the block valve are operating correctly so the potential for a LOCA through the PORV pathway is minimized, or if a LOCA were to occur through a failed open PORV, the block valve could be manually operated to isolate the path.

In the event of an abnormal transient, the PORVs may be manually operated to depressurize the PCS as directed by the Emergency Operating Procedures. The PORVs may be used for depressurization when the pressurizer spray is not available, a condition that may be encountered during a loss of offsite power. Operators can manually open the PORVs to reduce PCS pressure in the event of a Steam Generator Tube Rupture (SGTR) with offsite power unavailable.

The PORVs may also be used for once-through core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

BASES

BACKGROUND (continued)

If preferred during normal plant operation when PCS temperature is at or above 430°F and the PORV block valves are open, the PORVs may also function as an automatic overpressure device and limits challenges to the safety valves. Although the PORVs act as an overpressure device for operational purposes, safety analyses do not take credit for PORV actuation, but do take credit for the safety valves. Since the pressurizer safety valves provide the necessary automatic protection against excessive PCS pressure, automatic actuation of the PORVs is not required to be OPERABLE and the PORVs and their block valves are normally maintained in the closed position.

The PORVs also provide Low Temperature Overpressure Protection (LTOP) during heatup and cooldown. LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," addresses this function.

APPLICABLE SAFETY ANALYSES

The PORV small break LOCA break size is bounded by the spectrum of piping breaks analyzed for plant licensing. The possibility of a small break LOCA through the PORV is reduced when the PORV flow path is OPERABLE and the PORV opening setpoint is established to be reasonably remote from expected transient challenges. The possibility is further minimized if the flow path is isolated.

Overpressure protection is provided by safety valves, and analyses do not take credit for the PORV opening for accident mitigation. However, technical findings and regulatory analysis discussed in NUREG-1316, "Technical Findings and Regulatory Analysis Related to Generic Issue 70 - Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants," have determined that maintaining the requirements for PORVs and block valves in the technical specifications can increase the reliability of these components and provide assurance they will function as required and that operating experience has shown these components to be important to public health and safety.

Pressurizer PORVs satisfy Criterion 4 of 10 CFR 50.36(c)(2).

BASES

LCO

The LCO requires each PORV and its associated block valve to be OPERABLE. The block valve is required to be OPERABLE so it may be used to isolate the flow path of an inoperable PORV or, unisolate the flow path of an OPERABLE PORV. Thus, a block valve is considered OPERABLE if it is capable of being cycled in the open and close direction.

The PORV is required to be OPERABLE to provide PCS pressure control and maintain PCS integrity. For a PORV, OPERABILITY means the valve is capable of being cycled in the open and close direction.

APPLICABILITY

With a PORV in the "CLOSED" position in MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F, the PORV and its block valve are required to be OPERABLE to limit PCS leakage through the PORV flow path, and to be available for manual operation to mitigate abnormal transients which may be initiated from these MODES and condition.

With a PORV in the "AUTO" position in MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. A likely cause for PORV small break LOCA is a result of pressure increase transients that cause the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the PCS pressure to increase to the PORV opening setpoint. Pressure increase transients can occur any time the steam generators are used for heat removal. The most rapid increases will occur at higher operating power and pressure conditions of MODES 1 and 2. Pressure increases are less prominent in MODE 3 with PCS cold leg temperatures < 430°F because the core input energy is reduced, but the PCS pressure is high. Therefore, this LCO is applicable in MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F.

The LCO is not applicable in MODE 3 with any PCS cold leg temperatures < 430°F when both pressure and core energy are decreased and the pressure surges become much less significant. The PORV setpoint is reduced for LTOP in MODE 3 when any PCS cold leg temperatures are < 430°F, and in MODES 4, 5, and MODE 6 with the reactor vessel head in place. LCO 3.4.12 addresses the PORV requirements in these MODES.

BASES

ACTIONS

The ACTIONS are modified by two Notes. Note 1 clarifies that each pressurizer PORV is treated as a separate entity, each with separate Completion Times (i.e., the Completion Time is on a component basis). Note 2 is an exception to LCO 3.0.4. The exception for LCO 3.0.4 permits entry into MODES 1, 2, and 3 to perform cycling of the PORV to verify their OPERABLE status.

A.1 and A.2

If one PORV is inoperable it must either be isolated, by closing the associated block valve, or restored to OPERABLE status. The Completion Time of 1 hour is reasonable based on the small potential that the PORVs will be required to function during this time period and provides the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status.

B.1 and B.2

If one block valve is inoperable, then it must be restored to OPERABLE status, or the associated PORV placed in manual control. Placing a PORV in manual control is accomplished by placing the PORV hand switch in the "CLOSE" position. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable based on the small potential that the PORVs will be required to function during this time period and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status.

The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition A since the PORVs are not capable of automatically mitigating an overpressure event when placed in manual control. If the block valve is restored within the Completion Time of 72 hours, the PORV is restored to OPERABLE status.

BASES

ACTIONS (continued)

C.1 and C.2

If more than one PORV is inoperable, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing the associated block valves and restoring at least one PORV to OPERABLE status within 2 hours. The Completion Time of 1 hour is reasonable based on the small potential that the PORVs will be required to function during this time period, and provides the operator time to correct the situation. If one PORV is restored and one PORV remains inoperable, then the plant will be in Condition A with the time clock started at the original declaration of having two PORVs inoperable.

D.1 and D.2

If two block valves are 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 to OPERABLE status within 2 hours and the remaining block valve in 72 hours. The Completion Time of 1 hour to either restore the block valves or place the associated PORVs in manual control is reasonable based on the small potential that the PORVs will be required to function during this time period, and provides the operator time to correct the situation.

BASES

ACTIONS (continued)

E.1

If the Required Actions and associated Completion Times are not met, then the plant must be brought to a stable condition which minimizes the potential for transients affecting the PCS. The plant must be brought to at least MODE 3 within 6 hours. With one or two PORVs or block valves inoperable, exiting the MODE of Applicability (i.e., MODE 3 with any PCS cold leg temperature < 430°F) may not be desirable since below 430°F the PORVs and their associated block valves are required to support LTOP operations (LCO 3.4.12). Although LCO 3.0.4 would allow entry into LCO 3.4.12, reducing PCS temperature below 430°F may not be prudent since below 430°F the PORVs are credited in the safety analysis to protect the PCS from an inadvertent overpressure event. At or above 430°F, the PORVs are not credited in the safety analysis and thus have no safety function. If practical, the inoperable PORVs or block valves should be restored to an OPERABLE status while the PCS is above 430°F to avoid entering a plant condition where the PORVs are required for LTOP. If necessary, LCO 3.0.4 would allow the plant to be placed in MODE 5 to facilitate repairs. In this plant condition, overpressure protection may be provided by establishing the required vent path specified in LCO 3.4.12.

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 safety systems. In MODE 3 with any PCS cold leg temperature < 430°F, and MODES 4 and 5 and MODE 6 with the reactor vessel head on, maintaining PORV OPERABILITY is required by LCO 3.4.12.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that it can be opened and closed if necessary. The basis for the Frequency of "prior to entering MODE 4 from MODE 5 if not performed in the previous 92 days" reflects the importance of not routinely cycling the block valves during the period when the PCS is pressurized since this practice may result in the associated PORV being opened by the increase inlet pressure to the PORV. The "92 days" portion of the Frequency is consistent with the testing frequency stipulated by ASME Section XI as modified by the Cold Shutdown Testing Basis used in support of the second 120 month interval of the Inservice Valve Testing Program which only requires the block valves to be cycled during Cold Shutdown conditions. If the block valve is closed to isolate a PORV that is capable of being manually cycled, the OPERABILITY of the block valve is of importance because opening the block valve is necessary to permit the PORV to be used for manual control of primary coolant pressure. If a block valve is open and its associated PORV was stuck open, the OPERABILITY of the block valve is of importance because closing the block valve is necessary to isolate the stuck opened PORV.

SR 3.4.11.2

SR 3.4.11.2 requires complete cycling of each PORV. PORV cycling demonstrates its function and is performed when the PCS temperature is > 200°F. Stroke testing of the PORVs above 200°F is desirable since it closer simulates the temperature and pressure environmental effects on the valves and thus represents a better test condition for assessing PORV performance under normal plant conditions. The Frequency of 18 months is based on a typical refueling cycle and industry accepted practice.

REFERENCES None

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls PCS pressure at low temperatures so the integrity of the Primary Coolant Pressure Boundary (PCPB) 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 PCPB component for demonstrating such protection. LCO 3.4.3, "PCS Pressure and Temperature (P/T) Limits," provides the allowable combinations for operational pressure and temperature during cooldown, shutdown, and heatup to keep from violating the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperatures. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). PCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the PCS 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 PCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3 requires administrative control of PCS pressure and temperature during heatup and cooldown to prevent exceeding the P/T limits.

This LCO provides PCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all High Pressure Safety Injection (HPSI) pumps be incapable of injection into the PCS when any PCS cold leg temperature is < 300°F. The pressure relief capacity requires either two OPERABLE redundant Power Operated Relief Valves (PORVs) or the PCS depressurized and a PCS vent of sufficient size. One PORV or the PCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

BASES

BACKGROUND (continued)

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the chemical and volume control system deactivated or the Safety Injection Signals (SIS) blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the chemical and volume control system can provide adequate flow via the makeup control valve. If conditions require the use of an HPSI pump for makeup in the event of loss of inventory, then a pump can be made available through manual actions.

The LTOP System for pressure relief consists of two PORVs with temperature dependent lift settings or a PCS vent of sufficient size. Two PORVs are required for redundancy. One PORV has adequate relieving capability to prevent overpressurization for the allowed coolant input capability.

PORV Requirements

As designed for the LTOP System, each PORV is signaled to open if the PCS pressure approaches a limit determined by the LTOP actuation logic. The actuation logic monitors PCS pressure and cold leg temperature to determine when the LTOP overpressure setting is approached. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The LCO presents the PORV setpoints for LTOP by specifying Figure 3.4.12-1, "LTOP Setpoint Limit." Having the setpoints of both valves within the limits of the LCO ensures the P/T limits will not be exceeded in any analyzed event.

When a PORV is opened in an increasing pressure transient, the release of coolant causes the pressure increase to slow and reverse. As the PORV releases coolant, the system pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

BASES

BACKGROUND (continued)

PCS Vent Requirements

Once the PCS is depressurized, a vent exposed to the containment atmosphere will maintain the PCS at containment ambient pressure in an PCS 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.

Reference 3 has determined that any vent path capable of relieving 167 gpm at a PCS pressure of 315 psia is acceptable. The 167 gpm flow rate is based on an assumed charging imbalance due to interruption of letdown flow with three charging pumps operating, a 40°F per hour PCS heatup rate, a 60°F per hour pressurizer heatup rate, and an initially depressurized and vented PCS. Neither HPSI pump nor Primary Coolant Pump (PCP) starts need to be assumed with the PCS initially depressurized, because LCO 3.4.12 requires both HPSI pumps to be incapable of injection into the PCS and LCO 3.4.7, "PCS Loops-MODE 5, Loops Filled," places restrictions on starting a PCP.

The pressure relieving ability of a vent path depends not only upon the area of the vent opening, but also upon the configuration of the piping connecting the vent opening to the PCS. A long, or restrictive piping connection may prevent a larger vent opening from providing adequate flow, while a smaller opening immediately adjacent to the PCS would be adequate. The areas of multiple vent paths cannot simply be added to determine the necessary vent area.

The following vent path examples are acceptable:

1. Removal of a steam generator primary manway;

2. Removal of the pressurizer manway;

3. Removal of a PORV or pressurizer safety valve;

4. Both PORVs and associated block valves open; and

5. Opening of both PCS vent valves MV-PC514 and MV-PC515.

BASES

BACKGROUND (continued)

Reference 4 determined that venting the PCS through MV-PC514 and MV-PC515 provided adequate flow area. The other listed examples provide greater flow areas with less piping restriction and are therefore acceptable. Other vent paths shown to provide adequate capacity could also be used. The vent path(s) must be above the level of reactor coolant, so as not to drain the PCS when open.

One open PORV provides sufficient flow area to prevent excessive PCS pressure. However, if the PORVs are elected as the vent path, both valves must be used to meet the single failure criterion, since the PORVs are held open against spring pressure by energizing the operating solenoid.

When the shutdown cooling system is in service with MO-3015 and MO-3016 open, additional overpressure protection is provided by the relief valves on the shutdown cooling system. References 5 and 6 show that this relief capacity will prevent the PCS pressure from exceeding its pressure limits during any of the above mentioned events.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 7) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits during shutdown. In MODES 1 and 2, and in MODE 3 with all PCS cold leg temperature at or exceeding 430°F, the pressurizer safety valves prevent PCS pressure from exceeding the Reference 1 limits. Below 430°F, overpressure prevention falls to the OPERABLE PORVs or to a depressurized PCS and a sufficiently sized PCS 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 P/T limit curves are revised, the LTOP System will be re-evaluated to ensure its functional requirements can still be satisfied using the PORV method or the depressurized and vented PCS condition.

Reference 3 contains the acceptance limits that satisfy the LTOP requirements. Any change to the PCS must be evaluated against these analyses to determine the impact of the change on the LTOP acceptance limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Transients that are capable of overpressurizing the PCS are categorized as either mass or heat input transients, examples of which follow:

Mass Input Type Transients

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

Heat Input Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of Shutdown Cooling (SDC); or

c. PCP startup with temperature asymmetry within the PCS or between the PCS and steam generators.

Rendering both HPSI pumps, incapable of injection is required during the LTOP MODES to ensure that mass input transients do not occur, which either of the LTOP overpressure protection means cannot handle. The Reference 3 analyses demonstrate that either one PORV or the PCS vent can maintain PCS pressure below limits when three charging pump are actuated. Thus, the LCO prohibits the operation of both HPSI pumps and does not place any restrictions on charging pump operation.

Fracture mechanics analyses established the temperature of LTOP Applicability below 430°F. At and above this temperature, the pressurizer safety valves provide the reactor vessel pressure protection. The vessel materials were assumed to have a neutron irradiation accumulation equal to 2.192 E19 nvt.

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 setpoint curve specified in Figure 3.14.12-1 of the accompanying LCO. The setpoint is derived by modeling the performance of the LTOP System, assuming the limiting allowed LTOP transient. The valve qualification process considered pressure overshoot and undershoot beyond the PORV opening and closing setpoints, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensure the Reference 1 limits will be met.

The PORV setpoints will be re-evaluated for compliance when the P/T limits are revised. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to embrittlement caused by neutron irradiation. Revised P/T limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3 discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV represents the worst case, single active failure.

PCS Vent Performance

With the PCS depressurized, analyses show the required vent size is capable of mitigating the limiting allowed LTOP overpressure transient. In that event, this size vent maintains PCS pressure less than the maximum PCS pressure on the P/T limit curve.

The PCS vent is passive and is not subject to active failure.

LTOP System satisfies Criterion 2 of 10 CFR 50.36(c)(2).

BASES

LCO

This LCO is required to ensure that the LTOP System is OPERABLE. The LTOP System is OPERABLE when both HPSI pumps are incapable of injecting into the PCS and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, LCO 3.4.12.a requires both HPSI pumps be incapable of injecting into the PCS. LCO 3.4.12.a is modified by two Notes. Note 1 only requires both HPSI pumps to be incapable of injecting into the PCS when any PCS cold leg temperature is < 300°F. When all PCS cold leg temperatures are ≥ 300°F, a start of both HPSI pumps in conjunction with a charging/letdown imbalance will not cause the PCS pressure to exceed the 10 CFR 50 Appendix G limits. Thus, a restriction on HPSI pump operation when all PCS cold leg temperatures are ≥ 300°F is not required. Note 2 is provided to assure that this LCO does not cause hesitation in the use of a HPSI pump for PCS makeup if it is needed due to a loss of shutdown cooling or a loss of PCS inventory.

The elements of the LCO that provide overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs; or

b. The depressurized PCS and a PCS vent.

A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set consistent with Figure 3.4.12-1 in the accompanying LCO and testing has proven its ability to open at that setpoint, and motive power is available to the valve and its control circuit.

A PCS vent is OPERABLE when open with an area capable of relieving ≥ 167 gpm at a PCS pressure of 315 psia.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

BASES

APPLICABILITY

This LCO is applicable in MODE 3 when the temperature of any PCS cold leg is < 430°F, in MODES 4 and 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits at and above 430°F. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F.

Low temperature overpressure prevention is most critical during shutdown when the PCS is water solid, and a mass or heat input transient can cause a very rapid increase in PCS pressure when little or no time allows operator action to mitigate the event.

ACTIONS

A Note has been added in the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS, even though the ACTIONS may eventually require a plant shutdown. The intent of this exception is to allow the plant to enter the LTOP MODE with an inoperable PORV from MODES 1 and 2, and MODE 3 with all PCS cold leg temperature ≥ 430°F, to facilitate valve repairs. This exception is acceptable since the Required Actions provide the appropriate compensatory measures commensurate with PORV inoperabilites.

A.1

With one or two HPSI pumps capable of injecting into the PCS, overpressurization is possible.

The immediate Completion Time to initiate actions to restore restricted coolant input capability to the PCS reflects the importance of maintaining overpressure protection of the PCS.

BASES

ACTIONS (continued)

B.1

With one required PORV inoperable and pressurizer water level ≤ 57%, the required PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two valves are required to meet the LCO requirement and to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time is based on the facts that only one PORV 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 and, that a steam bubble exists in the pressurizer. Since the pressure response to a transient is greater if the pressurizer steam space is small or if PCS is solid, the allowed outage time for a PORV flow path out of service is shorter. The maximum pressurizer level at which credit can be taken for having a bubble (57%, which provides about 700 cubic feet of steam space) is based on judgement rather than verified by analysis. This level provides the same steam volume to dampen pressure transients as would be available at full power. This steam volume provides time for operator action, if the PORVs failed to operate, between an inadvertent SIS and PCS pressure reaching the 10 CFR 50, Appendix G pressure limit. The time available for action would depend upon the existing pressure and temperature when the inadvertent SIS occurred.

C.1

The consequences of operational events that will overpressure the PCS are more severe at lower temperature (Ref. 8). With the pressurizer water level > 57% less steam volume is available to dampen pressure increases resulting from an inadvertent mass or heat input transients. Thus, with one required PORV inoperable and the pressurizer water level > 57%, the Completion Time to restore the required PORV to OPERABLE status is 24 hours.

The 24 hour Completion Time to restore the required PORV to OPERABLE status when the pressurizer water level is > 57%, which usually occurs in MODE 5 or in MODE 6 when the vessel head is on, is a reasonable amount of time to investigate and repair several types of PORV failures without exposure to a lengthy period with only one PORV OPERABLE to protect against overpressure events.

BASES

ACTIONS (continued)

D.1

If two required PORVs are inoperable, or if the Required Actions and the associated Completion Times are not met, or if the LTOP System is inoperable for any reason other than Condition A, B, or C, the PCS must be depressurized and a vent established within 8 hours. The vent must be sized to provide a relieving capability of ≥ 167 gpm at a pressure of 315 psia which ensures the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action protects the PCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time of 8 hours to depressurize and vent the PCS is based on the time required to place the plant in this condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, both HPSI pumps are verified to be incapable of injecting into the PCS. The HPSI pumps are rendered incapable of injecting into the PCS by means that assure that a single event cannot cause overpressurization of the PCS due to operation of the pump. Typical methods for accomplishing this are by pulling the HPSI pump breaker control power fuses, racking out the HPSI pump motor circuit breaker, or closing the manual discharge valve.

SR 3.4.12.1 is modified by a Note which only requires the SR to be met when complying with LCO 3.4.12.a. When all PCS cold leg temperature are ≥ 300°F, a start of both HPSI pumps in conjunction with a charging/letdown imbalance will not cause the PCS pressure to exceed the 10 CFR 50 Appendix G limits. Thus, this SR is only required when any PCS cold leg temperature is reduced to less than 300°F.

The 12 hour interval considers operating practice to regularly assess potential degradation and to verify operation within the safety analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.2

SR 3.4.12.2 requires a verification that the required PCS vent, capable of relieving ≥ 167 gpm at a PCS pressure of 315 psia, is OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked open; or

b. Once every 31 days for a valve that is locked open.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance need only be performed if vent valves are being used to satisfy the requirements of this LCO. This Surveillance does not need to be performed for vent paths relying on the removal of a steam generator primary manway cover, pressurizer manway cover, safety valve or PORV since their position is adequately addressed using administrative controls and the inadvertent reinstallation of these components is unlikely. The Frequencies consider operating experience with mispositioning of unlocked and locked vent valves, respectively.

SR 3.4.12.3

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve can be remotely verified open in the main control room.

The block valve is a remotely controlled, motor operated valve. The power to the valve motor operator is not required to be removed, and the manual actuator 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 event.

The 72 hour Frequency considers operating experience with accidental movement of valves having remote control and position indication capabilities available where easily monitored. These considerations include the administrative controls over main control room access and equipment control.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.4

Performance of a CHANNEL FUNCTIONAL TEST is required every 31 days. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay This is acceptable because all of the Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. PORV actuation could depressurize the PCS and is not required. The 31 day Frequency considers experience with equipment reliability.

A Note has been added indicating this SR is required to be performed 12 hours after decreasing any PCS cold leg temperature to < 430°F. This Note allows a discrete period of time to perform the required test without delaying entry into the MODE of Applicability for LTOP. This option may be exercised in cases where an unplanned shutdown below 430°F is necessary as a result of a Required Action specifying a plant shutdown, or other plant evolutions requiring an expedited cooldown of the plant. The test must be performed within 12 hours after entering the LTOP MODES.

SR 3.4.12.5

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months to adjust the entire channel so that it responds and the valve opens within the required LTOP range and with accuracy to known input.

The 18 month Frequency considers operating experience with equipment reliability and is consistent with the typical refueling outage schedule.

BASES

REFERENCES

1. 10 CFR 50, Appendix G
2. Generic Letter 88-11
3. CPC Engineering Analysis, EA-A-PAL-92095-01
4. CPC Engineering Analysis, EA-TCD-91-01-01
5. CPC Engineering Analysis, EA-PAL-89-040-1
6. CPC Corrective Action Document, A-PAL-91-011
7. FSAR, Section 7.4
8. Generic Letter 90-06

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.13 PCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the PCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the PCS.

During plant life, the joint and valve interfaces can produce varying amounts of primary coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the PCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

10 CFR 50, Appendix A, GDC 30, requires means for detecting and, to the extent practical, identifying the source of primary coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 1) describes acceptable methods for selecting leakage detection systems.

The safety significance of PCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring primary 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 detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with PCS LEAKAGE detection.

This LCO deals with protection of the Primary Coolant Pressure Boundary (PCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analysis radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a Loss Of Coolant Accident (LOCA).

BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes 1 gpm primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a Main Steam Line Break (MSLB) 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 FSAR (Ref. 2) analysis for SGTR assumes the contaminated secondary fluid is released via the Main Steam Safety Valves and Atmospheric Dump Valves. The 1 gpm primary to secondary LEAKAGE is inconsequential, relative to the dose contribution from the affect SG.

The MSLB is more limiting for site radiation releases. The safety analysis for the MSLB accident assumes 1 gpm primary to secondary LEAKAGE in one generator as an initial condition. The dose consequences resulting from the MSLB accident are well within the guidelines defined in 10 CFR 100.

PCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

PCS 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 PCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

BASES

LCO (continued)

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 PCPB, 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 PCS makeup system. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled Primary Coolant Pump (PCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

LCO 3.4.14, "PCS 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 PCS LEAKAGE when the other is leaktight. If both valves leak and result in a loss of mass from the PCS, the loss must be included in the allowable identified LEAKAGE.

d. Primary to Secondary LEAKAGE through Any One SG

The 432 gallon per day limit on primary to secondary LEAKAGE through any one SG ensure the total primary to secondary LEAKAGE through both SGs produces acceptable offsite doses in the MSLB accident analysis. In addition, the LEAKAGE limit also ensures that SG integrity is maintained in the event of an MSLB or under LOCA conditions. Violation of this LCO could exceed the offsite dose limits for this accident analysis. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for PCPB LEAKAGE is greatest when the PCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the primary coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary 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 PCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists or if unidentified, identified, or primary to secondary 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. The reactor must be brought to MODE 3 within 6 hours and to MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the PCPB are much lower, and further deterioration is much less likely.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying PCS LEAKAGE to be within the LCO limits ensures the integrity of the PCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an PCS water inventory balance. Primary to secondary LEAKAGE is also measured by performance of an PCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.

The PCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. Therefore, this SR is modified by a Note which states that the SR is not required to be performed in MODES 3 and 4, until 12 hours of steady state operation have elapsed.

Steady state operation is required to perform a proper water inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met only when steady state is established. For PCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable PCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and PCP seal leakoff.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. These leakage detection systems are specified in LCO 3.4.15, "PCS Leakage Detection Instrumentation."

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. A Note under the Frequency column states that this SR is required to be performed during steady state operation.

SR 3.4.13.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.

BASES

REFERENCES

1. Regulatory Guide 1.45, May 1973

2. FSAR, Section 14.15

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.14 PCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

The Reactor Safety Study (RSS), WASH-1400 (Ref. 1), identified in pressurized water reactors, an inter-system Loss Of Coolant Accident (LOCA) which is a significant contributor to risk of core melt accidents (Event V). The design examined in the RSS contained in-series check valves isolating the high pressure Primary Coolant System (PCS) from the lower pressure safety injection piping. The scenario which leads to the Event V accident is initiated by the failure of these check valves to function as a pressure isolation barrier. This causes an overpressurization and rupture of the lower pressure piping which results in a LOCA that bypasses containment.

When pressure isolation is provided by two in-series check valves, and when failure of one valve in the pair can go undetected for a substantial length of time, verification of valve integrity is required. Since these valves are important to safety, they should be tested periodically to ensure low probability of gross failure. Periodic examination of check valves must be undertaken to verify that each valve is seated properly and functioning as a pressure isolation device. The testing will reduce the overall risk of an inter-system LOCA. The testing may be accomplished by direct volumetric leakage measurement or by other equivalent means capable of demonstrating that leakage limits are not exceeded. The PCS PIV LCO allows PCS 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 PIVs in series in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "PCS Operational LEAKAGE." This is true during operation only when the loss of PCS mass through two valves in series 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 leakage rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not PCS operational LEAKAGE if the other is leaktight.

BASES

BACKGROUND (continued)

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. Therefore, this specification also addresses the potential for overpressurization of the low pressure piping in the Shutdown Cooling (SDC) system caused by the inadvertent opening of the SDC suction valves (MO-3015 and MO-3016) when the PCS pressure is above the design pressure of the SDC System. The leakage limit is an indication that the PIVs between the PCS and the connecting systems are degraded or degrading. PIV leakage or inadvertent valve positioning could lead to overpressure of the low pressure piping or components. Failure consequences could be a LOCA outside of containment, an unanalyzed condition that could degrade the ability for low pressure injection.

PIVs are provided to isolate the PCS from the following systems:

a. Shutdown Cooling System; and

b. Safety Injection System.

The PIVs which are required to be leak tested are listed in FSAR Chapter 4.0.

Violation of this LCO could result in overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

APPLICABLE SAFETY ANALYSES

Reference 1 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 low pressure piping outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the Primary Coolant Pressure Boundary (PCPB), and the subsequent pressurization of the lower pressure piping downstream of the PIVs from the PCS. Overpressurization failure of the lower pressure piping would result in a LOCA outside containment and subsequent risk of core melt.

Reference 2 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.

PCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2).

BASES

LCO

PCS PIV leakage is identified LEAKAGE into closed systems connected to the PCS. 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 a maximum of 5 gpm. Reference 3 permits leakage testing at a lower pressure differential than between the specified maximum PCS pressure and the normal pressure of the connected system during PCS 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.

The LCO also requires the SDC suction valve interlocks to be OPERABLE in order to prevent the inadvertent opening of the SDC suction valves when PCS pressure is above the 300 psig design pressure of the SDC suction piping. When PCS pressure is ≥ 280 psia as sensed by the pressurizer narrow range pressure channels, an inhibit signal is placed on the control circuit for the SDC suction valves which prevents the valves from opening and thus avoiding a potential overpressurization event of the SDC piping. For the SDC suction valve interlocks to be OPERABLE, two channels of pressurizer narrow range pressure instruments must be capable of providing an open inhibit signal to their respective isolation valve.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the PCS is pressurized. In MODE 4, the requirements of this LCO are not required when in, or during the transition to or from, the SDC mode of operation since these evolutions are performed when PCS pressure is less than the limiting design pressure of the systems addressed by this specification.

In MODES 5 and 6, leakage limits are not provided because the lower primary coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

BASES

ACTIONS

The ACTIONS are modified by two Notes. Note 1 is added to provide clarification that each flow path allows separate entry into a Condition. This is allowed based on the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

Required Action A.1 requires that isolation with one valve must be performed within 4 hours whenever one or more flow paths with leakage from one or more PIVs is not within limits. Four hours provides time to reduce leakage in excess of the allowable limit or to isolate the flow path if leakage cannot be reduced. The 4 hours allows the actions and restricts the operation with leaking isolation valves. Required Action A.1 is modified by a Note stating that the valves used for isolation must meet the same leakage requirement as the PIVs and must be in the PCPB or the high pressure portion of the system.

The 72 hour Completion Time after exceeding the limit allows for the restoration of the leaking PIV to OPERABLE status. This time frame considers the time required to complete this action and the low probability of a second valve failing during this period.

B.1 and B.2

If leakage cannot be reduced or if the affected system can not be isolated within the specified 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 to MODE 5 within 36 hours. This action reduces the leakage and also reduces the potential for a LOCA outside the containment. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1

The inoperability of the SDC suction valve interlocks renders the SDC suction isolation valves incapable of preventing an inadvertent opening of the valves at PCS pressures in excess of the SDC systems design pressure. If the SDC suction valve interlocks are inoperable, operation may continue as long as the suction penetration is closed by at least one closed deactivated valve within 4 hours. This action accomplishes the purpose of the interlock. The 4 hour Completion Time provides time to accomplish the action and restricts operation with an inoperable interlock.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each PCS PIV or isolation valve used to satisfy Required Action A.1 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 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. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed every 9 months whenever the plant has been in MODE 5 for 7 days or more, but may be extended up to a maximum of 18 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 18 month Frequency is consistent with 10 CFR 50.55a(g), as contained in the Inservice Testing Program, is within the frequency allowed by the American Society of Mechanical Engineers (ASME) Code, Section XI, and is based on the need to perform the Surveillance under conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

The leakage limit is to be met at the PCS 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

SR 3.4.14.1 is modified by three Notes. Note 1 states that the SR is only required to be performed in MODES 1 and 2. Entry into MODES 3 and 4 is allowed to establish the necessary differential pressure and stable conditions to allow performance of this surveillance.

Note 2 further restricts the PIV leakage rate acceptance criteria by limiting the reduction in margin between the measured leakage rate and the maximum permissible leakage rate by 50% or greater. Reductions in margin by 50% or greater may be indicative of PIV degradation and warrant inspection or additional testing. Thus, leakage rates less than 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

Note 3 limits the minimum test differential pressure to 150 psid during performance of PIV leakage testing.

SR 3.4.14.2

Verifying that the SDC suction valve interlocks are OPERABLE ensures that PCS pressure will not pressurize the SDC system beyond 125% of its design pressure of 300 psig. The interlock setpoint that prevents the valves from being opened is set so the actual PCS pressure must be < 280 psia to open the valves. This setpoint ensures the SDC design pressure will not be exceeded and the SDC relief valves will not lift. The narrow range pressure transmitters that provide the SDC suction valve interlocks are sensed from the pressurizer. Due to the elevation differences between these narrow range pressure transmitter calibration points and the SDC suction piping, the pressure in the SDC suction piping will be higher than the indicated pressurizer pressure. Due to this pressure difference, the SDC suction valve interlocks are conservatively set at or below 280 psia to ensure that the 300 psig (315 psia) design pressure of the suction piping is not exceeded. The 18 month Frequency is based on the need to perform these Surveillances under conditions that apply during a plant outage. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.14.3

This SR requires a verification that the four Low Pressure Safety Injection (LPSI) check valves (CK-3103, CK-3118, CK-3133 and CK-3148) in the SDC flow path reclose after stopping SDC flow. Performance of this SR is necessary to ensure the LPSI check valves are closed to prevent overpressurization of the LPSI subsystem from the High Pressure Safety Injection (HPSI) subsystem. Overpressurization of the LPSI piping could occur if the LPSI check valves were not closed upon the receipt of a Safety Injection Signal and PCS pressure remained relatively high (e.g., during a small break LOCA). In this case, the higher pressure water from the discharge of the HPSI pumps could cause the lower pressure LPSI piping to exceed its design pressure. This event could result in a loss of emergency core cooling water outside containment which reduces the overall volume of water available for recirculation from the containment sump (Ref. 4).

SR 3.4.14.3 is required to be performed on a Frequency of "prior to entering MODE 2 whenever the LPSI check valves have been used for SDC." This ensures the LPSI check valves are closed whenever they have been opened for SDC operations prior to a reactor startup. The SR is modified by a Note which states that the surveillance is only required to be performed in MODES 1 and 2. Thus, entry into MODES 3 and 4 is allowed to establish the necessary differential pressure and to establish stable conditions to allow performance of this surveillance.

REFERENCES

1. WASH-1400 (NUREG-75/014), Appendix V, October 1975

2. NUREG-0677, May 1980

3. ASME, Boiler and Pressure Vessel Code, Section XI

4. Letter from Consumers Power Company to D.M. Crutchfield (NRC) Requesting a Change to the Palisades Plant Technical Specification, dated July 29, 1982

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.15 PCS Leakage Detection Instrumentation

BASES

BACKGROUND

The Palisades Nuclear Plant design criteria (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of PCS LEAKAGE.

Leakage detection instrumentation must have the capability to detect significant Primary Coolant Pressure Boundary (PCPB) 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.

Industry practice has shown that water flow changes of 0.5 gpm to 1.0 gpm can readily be detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump, used to collect unidentified LEAKAGE, is instrumented in the containment sump drain line with level transmitters providing sump level indication in the control room. The sensitivity of these instruments is acceptable for detecting increases in unidentified LEAKAGE.

The primary coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Primary 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. An instrument sensitivity capable of detecting a 100 cm^3/min leak in 45 minutes based on 1% failed fuel is practical for the leakage detection instrument (Ref. 2). Radioactivity detection is included for monitoring gaseous activities because of its sensitivity and rapid responses to PCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Humidity detectors are capable of detecting a 10% change in humidity which would result from approximately 150 gallons of primary water leakage (Ref. 2).

BASES

BACKGROUND (continued)

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment sump and condensate flow from air coolers. Humidity level monitoring is considered most useful as an indirect indication to alert the operator to a potential problem.

The containment air cooler design includes a sump with a drain, a liquid level switch, and an overflow path. Normally, very little water will be condensed from the containment atmosphere and the small amount of condensate will easily flow out through the sump drain. If leakage through the drain is greater than 25 gpm, the level in the sump will rise to the liquid level switch (approximately 6 inches from the bottom of the sump) and triggers an alarm in the control room to alert the operators of the excessive cooling coil drainage. Excessive drain water flow from the coils is indicative of a service water leak, steam leak, or a primary coolant system leak. A steam leak or primary coolant leak would be accompanied by an increase in the containment atmosphere humidity which would be detected by the containment humidity sensors and displayed in the control room. Since excessive containment air cooler drainage may be attributed to causes other than PCS LEAKAGE, an evaluation of PCS LEAKAGE should be confirmed using diverse instrumentation required by this specification.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate during plant operation, but a rise above the normally indicated range of values may indicate PCS LEAKAGE into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system sensitivities are described in the FSAR (Ref. 2). Multiple instrument locations are utilized, if needed, to ensure the transport delay time of the LEAKAGE from its source to an instrument location is acceptable.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety significance of PCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring PCS LEAKAGE into the containment area are necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should leakage occur detrimental to the safety of the facility and the public.

PCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2).

LCO

One method of protecting against large PCS LEAKAGE derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition when PCS LEAKAGE indicates possible PCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, a combination which includes one instrument channel from each of any three of the following; containment sump level indication, gaseous activity monitor, containment air cooler condensate level switch, or containment humidity monitor provides an acceptable minimum. For the containment air cooler condensate level switch only an operating containment air cooler may be relied upon to fulfill the LCO requirements for an OPERABLE leakage detection instrument.

APPLICABILITY

Because of elevated PCS temperature and pressure in MODES 1, 2, 3, and 4, PCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is $\leq$ 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 is much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

BASES

ACTIONS

The ACTIONS are modified by a Note that indicates the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one or two required leak detection instrument channels are inoperable. This allowance is provided because other instrumentation is available to monitor for PCS LEAKAGE.

A.1 and A.2

If one or two required leak detection instrument channels are inoperable, a periodic surveillance for PCS 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.

Restoration of the required instrument channels to an OPERABLE status is required to regain the function in a Completion Time of 30 days after the instrument's failure. This time is acceptable considering the frequency and adequacy of the PCS water inventory balance required by Required Action A.1.

B.1 and B.2

If the Required Action cannot be met 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.

C.1

If all required monitors are inoperable, no automatic means of monitoring leakage are available and immediate plant shutdown in accordance with LCO 3.0.3 is required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1, SR 3.4.15.2, and SR 3.4.15.3

These SRs require the performance of a CHANNEL CHECK for each required containment sump level indicator, containment atmosphere gaseous activity monitor, and containment atmosphere humidity monitor. The check gives reasonable confidence the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.4

SR 3.4.15.4 requires the performance of a CHANNEL FUNCTIONAL TEST of the required containment air cooler condensate level switch. Since this instrumentation does not include control room indication of flow rate, a CHANNEL CHECK is not possible. The test ensures that the level switch can perform its function in the desired manner. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Frequency of 18 months is a typical refueling cycle (performance of the test is only practical during a plant outage) and considers instrument reliability. Operating experience has shown this Frequency is acceptable for detecting degradation.

SR 3.4.15.5, SR 3.4.15.6, and SR 3.4.15.7

These SRs require the performance of a CHANNEL CALIBRATION for each required containment sump level, containment atmosphere gaseous activity, and containment atmosphere humidity channel. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Operating experience has shown this Frequency is acceptable.

BASES

REFERENCES

1. FSAR, Section 5.1.5

2. FSAR, Sections 4.7 and 6.3

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.16 PCS Specific Activity

BASES

BACKGROUND

10 CFR 100.11 specifies the maximum dose to the whole body and the thyroid an individual at the site boundary can receive for 2 hours during an accident. The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 guideline limits during analyzed transients and accidents.

The PCS specific activity LCO limits the allowable concentration level of radionuclides in the primary coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a Steam Generator Tube Rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to a small fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for an SGTR accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the primary coolant ensure that the resulting 2 hour doses at the site boundary will not exceed a small fraction of the 10 CFR 100 dose guideline limits following an SGTR accident. The SGTR safety analysis (Ref. 1) assumes the specific activity of the primary coolant at the LCO limits and an existing primary coolant Steam Generator (SG) tube leakage rate of 1 gpm. The analysis also assumes a reactor trip and a turbine trip at the same time as the SGTR event.

The analysis for the SGTR accident establishes the acceptance limits for PCS specific activity. Reference to this analysis is used to assess changes to the facility that could affect PCS specific activity as they relate to the acceptance limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The rise in pressure in the ruptured SG causes radioactive contaminated steam to discharge to the atmosphere through the atmospheric dump valves or the main steam safety valves. The atmospheric discharge stops when the affected SG is isolated below approximately 525°F. The unaffected SG removes core decay heat by venting steam until Shutdown Cooling conditions are reached.

The safety analysis shows the radiological consequences of an SGTR accident are within a small fraction of the 10 CFR 100 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limit of 40 μCi/gm for more than 48 hours.

This is acceptable because of the low probability of an SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

PCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

The specific iodine activity is limited to 1.0 µCi/gm DOSE EQUIVALENT I-131, and the gross specific activity in the primary coolant is limited to the number of µCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy). The limit on DOSE EQUIVALENT I-131 ensures the 2 hour thyroid dose to an individual at the site boundary during the Design Basis Accident (DBA) will be a small fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose.

The SGTR accident analysis (Ref. 1) shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in primary coolant radioactivity levels that could, in the event of an SGTR, lead to site boundary doses that exceed the 10 CFR 100 dose guideline limits.

BASES

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with PCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity is necessary to contain the potential consequences of an SGTR to within the acceptable site boundary dose values.

For operation in MODE 3 with PCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of an SGTR is unlikely since the saturation pressure of the primary coolant is below the lift pressure settings of the atmospheric dump valves and main steam safety valves.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate the limit 40 μCi/gm is not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample.

Sampling must continue for trending. The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours.

The Completion Time of 48 hours is required if the limit violation resulted from normal iodine spiking.

A Note to the Required Actions of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

BASES

ACTIONS (continued)

B.1

If a Required Action and associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is 40 μCi/gm or above, or with the gross specific activity in excess of the allowed limit, the plant must be placed in MODE in which the requirement does not apply.

The change within 6 hours to MODE 3 with PCS average temperature < 500°F lowers the saturation pressure of the primary coolant below the setpoints of the main steam safety valves and prevents venting the SG to the environment in an SGTR event. The allowed Completion Time of 6 hours is required to reach MODE 3 below 500°F from full power conditions and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

The Surveillance requires performing a gamma isotopic analysis as a measure of the gross specific activity of the primary coolant at least once per 7 days. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with PCS average temperature at least 500°F. The 7 day Frequency considers the unlikelihood of a gross fuel failure during the time.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.2

This Surveillance is performed to ensure iodine remains within limit during normal operation and following fast power changes when fuel failure is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level considering gross activity is monitored every 7 days. The Frequency, between 2 hours and 6 hours after a power change of ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results. This SR is modified by a Note which states that the SR is only required to be performed in MODE 1.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required every 184 days (6 months) with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. The Frequency of 184 days recognizes $\bar{E}$ does not change rapidly.

This SR has been modified by a Note that indicates sampling is required to be performed within 31 days after 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. FSAR, Section 14.15

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Safety Injection Tanks (SITs)

BASES

BACKGROUND

The functions of the four SITs are to supply water to the reactor vessel during the blowdown phase of a Loss of Coolant Accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Primary Coolant System (PCS) makeup for a small break LOCA.

The blowdown phase of a LOCA is the initial period of the transient during which the PCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the primary coolant. The blowdown phase of the transient ends when the PCS pressure falls to a value approaching that of the containment atmosphere.

The refill phase of a LOCA follows immediately after the primary coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of the SITs' inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of Safety Injection (SI) water.

The SITs are pressure vessels partially filled with borated water and pressurized with nitrogen gas (Ref. 2). The SITs are passive components, since no operator or control action is required for them to perform their function. Internal tank pressure and elevation head are sufficient to discharge the contents to the PCS, if PCS pressure decreases below the SIT pressure.

Each SIT is piped into one PCS cold leg via the injection lines utilized by the High Pressure Safety Injection and Low Pressure Safety Injection (HPSI and LPSI) systems. Each SIT is isolated from the PCS by a motor operated isolation valve and two check valves in series. The motor operated isolation valves are normally open, with power removed from the valve motor to prevent inadvertent closure prior to or during an accident.

BASES

BACKGROUND (continued)

The SIT gas and water volumes, gas pressure, tank elevation, and outlet pipe size are selected to allow three of the four SITs to partially recover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three SITs are adequate for this function is consistent with the LOCA assumption that the entire contents of one SIT will be lost via the break during the blowdown phase of a LOCA.

APPLICABLE SAFETY ANALYSES

The SITs are credited in both the large and small break LOCA analyses at full power (Ref. 1). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the SITs. Reference to the analyses for these DBAs is used to assess changes to the SITs as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of SI flow. These assumptions include signal generation time, equipment starting times, and delivery time due to system piping. In the early stages of a LOCA with a loss of offsite power, the SITs provide the sole source of makeup water to the PCS. (The assumption of a loss of offsite power is required by regulations.) This is because the LPSI pumps and HPSI pumps cannot deliver flow until the Diesel Generators (DGs) start, come to rated speed, and go through their timed loading sequence. In cold leg breaks, the entire contents of one SIT are assumed to be lost through the break during the blowdown and reflood phases.

The limiting large break LOCA is a double ended guillotine cold leg break at the discharge of the primary coolant pump. During this event, the SITs discharge to the PCS as soon as PCS pressure decreases to below SIT pressure. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA assumes a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated initially by the SITs, with pumped flow then providing continued cooling.

As break size decreases, the SITs and HPSI pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the SITs continues to decrease until they are not required, and the HPSI pumps become solely responsible for terminating the temperature increase.

BASES

APPLICABLE SAFETY ANALYSES (continued)

This LCO helps to ensure that the following acceptance criteria, established by 10 CFR 50.46 for the ECCS, will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. The core is maintained in a coolable geometry.

Since the SITs discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

Since the SITs are passive components, single active failures are not applicable to their operation. The SIT isolation valves, however, are not single failure proof; therefore, whenever the valves are open, power is removed from their operators and the switch is key locked open.

These precautions ensure that the SITs are available during an accident. With power supplied to the valves, a single active failure could result in a valve closure, which would render one SIT unavailable for injection. If the contents of a second SIT is lost through the break, only the contents of two SITs would reach the core. Since the only active failure that could affect the SITs would be the closure of a motor operated outlet valve, the requirement to remove power from these eliminates this failure mode.

The minimum volume requirement for the SITs ensures that three SITs can provide adequate inventory to reflood the core and downcomer following a LOCA. The downcomer then remains flooded until the HPSI and LPSI systems start to deliver flow.

The maximum volume limit is based on maintaining an adequate gas volume to ensure proper injection and the ability of the SITs to fully discharge, as well as limiting the maximum boron inventory in the SITs.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The minimum SIT volume of 1040 ft^3 and the maximum SIT volume of 1176 ft^3 correspond to a level of 174 inches and 200 inches, respectively. Each SIT is equipped with two float type level switches which activate control room alarms on high and low level. To allow for instrument inaccuracy, the low SIT level switch alarm is set at 176 inches and the high SIT alarm is set at 198 inches. As a backup to the SIT level switches and to facilitate operator use, level indication is also provided by a differential pressure transmitter which displays in percent tank level. The narrow indicating range of the differential pressure transmitter contains high and low alarms. The high level alarm trips at a slightly lower level than the high level switch and the low level alarm trips at a slightly higher level than the low level switch to alert the operator they are approaching the technical specification values.

The minimum nitrogen cover pressure requirement ensures that the contained gas volume will generate discharge flow rates during injection that are consistent with those assumed in the safety analyses.

A minimum pressure of 200 psig is used in the analyses. Each of the four SITs is equipped with two pressure switches and one pressure transmitter. The pressure switches activate separate control room alarms. One pressure switch provides a high pressure alarm and the other provides a low pressure alarm. The pressure transmitter provides a display of tank pressure and a common high/low pressure alarm. The low pressure alarms from the pressure switch and pressure transmitter are set sufficiently above the 200 psig value used in the safety analysis to provide margin for instrument inaccuracies. The high pressure alarms from the pressure switch and pressure transmitter are set well below the 250 psig tank design pressure and sufficiently above the normal operating pressure to avoid nuisance alarms.

The 1720 ppm limit for minimum boron concentration was established to ensure that, following a LOCA with a minimum level in the SITs, the reactor will remain subcritical in the cold condition following mixing of the SITs, Safety Injection Refueling Water Tank and PCS water volumes. Small break LOCAs assume that all full-length control rods are inserted, except for the control rod of highest worth, which is withdrawn from the core. Large break LOCA analyses assume that all full-length control rods remain withdrawn until the blowdown phase is over. For large break LOCAs, the initial reactor shutdown is accomplished by void formation. The most limiting case occurs at beginning of core life.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The maximum boron limit of 2500 ppm in the SITs is based on boron precipitation in the core following a LOCA. With the reactor vessel at saturated conditions, the core dissipates heat by boiling. Because of this boiling phenomenon in the core, the boric acid concentration will increase in this region. If allowed to proceed in this manner, a point will be reached where boron precipitation will occur in the core. Post LOCA emergency procedures direct the operator to establish simultaneous hot and cold leg injection to prevent this condition by establishing a forced flow path through the core regardless of break location. These procedures are based on the minimum time in which precipitation could occur, assuming that maximum boron concentrations exist in the borated water sources used for injection following a LOCA. Boron concentrations in the SITs in excess of the limit could result in precipitation earlier than assumed in the analysis.

The SITs satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The LCO establishes the minimum conditions required to ensure that the SITs are available to accomplish their core cooling safety function following a LOCA. Four SITs are required to be OPERABLE to ensure that 100% of the contents of three of the SITs will reach the core during a LOCA.

This is consistent with the assumption that the contents of one tank spill through the break. If the contents of fewer than three tanks are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 could be violated.

For an SIT to be considered OPERABLE, the isolation valve must be fully open, with power to the valve operator removed, and the limits established in the SR for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2 the SIT OPERABILITY requirements are based on an assumption of full power operation. Although cooling requirements decrease as power decreases, the SITs are required to be OPERABLE during the MODES when the reactor is critical.

In MODE 3 and below, the rate of PCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 limit of 2200°F.

BASES

APPLICABILITY (continued)

In MODES 3, 4, 5, and 6, the SIT motor operated isolation valves may be closed to isolate the SITs from the PCS. This allows PCS cooldown and depressurization without discharging the SITs into the PCS or requiring depressurization of the SITs.

ACTIONS

A.1

If the boron concentration of one SIT 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, but the reduced concentration effects on core subcriticality during reflood are minor. Boiling of the ECCS water in the core during reflood concentrates the boron in the saturated liquid that remains in the core. In addition, the volume of the SIT is still available for injection.

Since the boron requirements are based on the average boron concentration of the total volume of three SITs, the consequences are less severe than they would be if an SIT were not available for injection.

Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one SIT is inoperable, for a reason other than boron concentration or the inability to verify level or pressure, the SIT must be returned to OPERABLE status within 1 hour. In this Condition, the required contents of three SITs 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 1 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable SIT to OPERABLE status. The Completion Time minimizes the exposure of the plant to a LOCA in these conditions.

BASES

ACTIONS (continued)

C.1

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

D.1

If more than one SIT 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

Verification every 12 hours that each SIT isolation valve is fully open, as indicated in the control room, ensures that SITs are available for injection and ensures timely discovery if a valve should be partially closed. If an isolation valve is not fully open, the rate of injection to the PCS would be reduced. Although a motor operated valve should not change position with power removed, a closed valve could result in not meeting accident analysis assumptions. A 12 hour Frequency is considered reasonable in view of other administrative controls that ensure the unlikelihood of a mispositioned isolation valve.

SR 3.5.1.2 and SR 3.5.1.3

SIT borated water volume and nitrogen cover pressure should be verified to be within specified limits every 12 hours in order to ensure adequate injection during a LOCA. Due to the static design of the SITs, a 12 hour Frequency usually allows the operator sufficient time to identify changes before the limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

Thirty-one days is reasonable for verification to determine that each SIT's boron concentration is within the required limits, because the static design of the SITs limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage.

SR 3.5.1.5

Verification every 31 days that power is removed from each SIT isolation valve operator ensures that an active failure could not result in the undetected closure of an SIT motor operated isolation valve. If this were to occur, only two SITs would be available for injection, given a single failure coincident with a LOCA. Since installation and removal of power to the SIT isolation valve operators is conducted under administrative control, the 31 day Frequency was chosen to provide additional assurance that power is removed.

REFERENCES

1. FSAR, Section 14.17

2. FSAR, Chapter 6.1

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);

b. Control Rod Ejection accident;

c. Loss of secondary coolant accident, including a Main Steam Line Break (MSLB) or Loss of Normal 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.

There are two phases of ECCS operation: injection and recirculation. In the injection phase, all injection is initially added to the Primary Coolant System (PCS) via the cold legs. After the Safety Injection Refueling Water Tank (SIRWT) has been depleted, the recirculation phase is entered as the ECCS suction is automatically transferred to the containment sump.

Two suitably redundant, 100% capacity trains are provided. Each train consists of a High Pressure Safety Injection (HPSI) and Low Pressure Safety Injection (LPSI) subsystem. In MODES 1 and 2, and in MODE 3 with PCS temperature ≥ 325°F, both trains must be OPERABLE. This ensures that 100% of the core cooling requirements can be provided in the event of a single active failure.

BASES

BACKGROUND (continued)

Each train of a Safety Injection Signal (SIS) actuates LPSI flow by starting one LPSI pump and opening two LPSI loop injection valves. Each train of an SIS actuates HPSI flow by starting one HPSI pump, opening the four associated HPSI loop injection valves, and closing the pressure control valves associated with each Safety Injection Tank. In addition, each train of a SIS will provide a confirmatory open signal to the normally open Component Cooling Water valves which supply seal and bearing cooling to the LPSI, HPSI, and Containment Spray pumps.

The safety analyses assume that one only train of safety injection is available to mitigate an accident. While operating under the provisions of an ACTION, an additional single failure need not be assumed in assuring that a loss of function has not occurred. Therefore, the LPSI flow assumed in the safety analyses can be met if there is an OPERABLE LPSI flow path from the SIRWT to any two PCS loops. The HPSI flow assumed in the safety analyses can be met if there is an OPERABLE HPSI flow path from the SIRWT to each cold leg. In each case, an OPERABLE flow path must include an OPERABLE pump and an OPERABLE injection valve.

A suction header supplies water from the SIRWT or the containment sump to the ECCS pumps. Separate piping supplies each train. The discharge headers from each HPSI pump divide into four supply lines after entering the containment, one feeding each PCS cold leg. The discharge headers from each LPSI pump combine to supply a common header which divides into four supply lines after entering containment, one feeding each PCS cold leg.

Motor operated valves are set to maximize the LPSI flow to the PCS. This flow balance directs sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the PCS cold legs.

For LOCAs coincident with a loss of off-site power that are too small to initially depressurize the PCS below the shutoff head of the HPSI pumps, the core cooling function is provided by the Steam Generators (SGs) until the PCS pressure decreases below the HPSI pump shutoff head.

During low temperature conditions in the PCS, limitations are placed on the maximum number of HPSI 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.

BASES

BACKGROUND (continued)

During a large break LOCA, PCS pressure could decrease to < 200 psia in < 20 seconds. The ECCS systems are actuated upon receipt of an SIS. If offsite power is available, the safeguard loads start immediately. If offsite power is not available, all loads will be shed at the time the diesel generators receive an automatic start signal. With load shedding completed, the diesel generator breakers will close automatically when generator voltage approaches a normal operating value. Closing of the breakers will reset the load shedding signals and start the sequencer. The sequencers will initiate operation of the engineered safeguard equipment required for the accident. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive Safety Injection Tanks (SITs) and the Safety Injection Refueling Water Tank (SIRWT), covered in LCO 3.5.1, "Safety Injection Tanks (SITs)," and LCO 3.5.4, "Safety Injection Refueling Water Tank (SIRWT)," provide the cooling water necessary to meet the Palisades Nuclear Plant design criteria (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria, established by 10 CFR 50.46 for ECCSs, will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both a HPSI and a LPSI subsystem are assumed to be OPERABLE in the large break LOCA analysis at full power (Ref. 2). This analysis establishes a minimum required runout flow for the HPSI and LPSI pumps, as well as the maximum required response time for their actuation. The HPSI pump is also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head requirements at the design point for the HPSI pump. The SGTR and MSLB accident analyses also credit the HPSI pumps, but are not limiting in their design.

The large break LOCA event with a loss of offsite power and a single failure (disabling one ECCS train) establishes the OPERABILITY requirements for the ECCS. During the blowdown stage of a LOCA, the PCS 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 (during 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.

On smaller breaks, PCS pressure will stabilize at a value dependent upon break size, heat load, and injection flow. The smaller the break, the higher this equilibrium pressure. In all LOCA analyses, injection flow is not credited until PCS pressure drops below the shutoff head of the HPSI pumps.

The LCO ensures that an ECCS train will deliver sufficient water to match decay heat boiloff rates soon enough to minimize core damage for a large LOCA. It also ensures that the HPSI pump will deliver sufficient water during a small break LOCA and provide sufficient boron to limit the return to power following an MSLB event. For smaller LOCAs, PCS inventory decreases until the PCS can be depressurized below the HPSI pumps' shutoff head. During this period of a small break LOCA, the SGs continue to serve as the heat sink providing core cooling.

ECCS - Operating satisfies Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

In MODES 1 and 2, and in MODE 3 with PCS temperature ≥ 325°F, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming there is 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.

An ECCS train consists of an HPSI subsystem and a LPSI subsystem. In addition, each train includes the piping, instruments, and controls to ensure the availability of an OPERABLE flow path capable of taking suction from the SIRWT on an SIS and automatically transferring suction to the containment sump upon a Recirculation Actuation Signal (RAS).

During an event requiring ECCS actuation, a flow path is provided to ensure an abundant supply of water from the SIRWT to the PCS, via the HPSI and LPSI pumps and their respective supply headers, to each of the four cold leg injection nozzles is available. During the recirculation phase, a flow path is provided from the containment sump to the PCS via the HPSI pumps. For worst case conditions, the containment building water level alone is not sufficient to assure adequate Net Positive Suction Head (NPSH) for the HPSI pumps. Therefore, to obtain adequate NPSH, a portion of the Containment Spray (CS) pump discharge flow is diverted from downstream of the shutdown cooling heat exchangers to the suction of the HPSI pumps following recirculation during a large break LOCA. In this configuration, the CS pumps and shutdown cooling heat exchangers provide a support function for HPSI flow path OPERABILITY. The OPERABILITY requirements for the CS pumps and shutdown cooling heat exchangers are addressed in LCO 3.6.6, "Containment Cooling Systems." Support system OPERABILITY is addressed by LCO 3.0.6.

The flow path for each train must maintain its designed independence to ensure that no single active failure can disable both ECCS trains.

BASES

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with PCS temperature ≥ 325°F, the ECCS OPERABILITY requirements for the limiting Design Basis Accident (DBA) 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 HPSI pump performance is based on the small break LOCA, which establishes the pump performance curve and has less dependence on power. The requirements of MODE 2 and MODE 3 with PCS temperature ≥ 325°F, are bounded by the MODE 1 analysis.

The ECCS functional requirements of MODE 3, with PCS temperature < 325°F, and MODE 4 are described in LCO 3.5.3, "ECCS - Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "PCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "PCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

If one or more trains are inoperable, but at least 100% of the flow assumed to be delivered by a single OPERABLE ECCS train is available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC study (Ref. 3) using a reliability evaluation and is a reasonable amount of time to effect many repairs.

An ECCS train is inoperable if it is not capable of delivering the assumed flow to the PCS. The individual components are inoperable if they are not capable of performing their required function, or if supporting systems are not available.

BASES

ACTIONS

A.1 (continued)

The safety analyses assume that only one train of safety injection is available to mitigate an accident. While operating under the provisions of an ACTION, an additional single failure need not be assumed in assuring that a loss of function has not occurred. Therefore, the LPSI flow assumed in the safety analyses can be met if there is an OPERABLE LPSI flow path from the SIRWT to any two PCS loops. The HPSI flow assumed in the safety analyses can be met if there is an OPERABLE HPSI flow path from the SIRWT to each PCS loop. In each case, an OPERABLE flow path must include an OPERABLE pump and an OPERABLE loop injection valve.

The LCO requires the OPERABILITY of two independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not necessarily 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 OPERABLE equipment such that 100% of the ECCS flow assumed to be delivered by a single OPERABLE train remains available. This allows increased flexibility in plant operations when components in opposite trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an emergency DG can disable one ECCS train until power is restored. A reliability analysis (Ref. 4) has shown that the impact with one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 4 describes situations in which one component, such as the shutdown cooling flow control valve, CV-3006, can disable both ECCS trains. With one or more components inoperable, such that 100% of the flow assumed to be delivered by a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be immediately entered.

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and PCS temperature reduce to < 325°F within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power 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 PCS is maintained. CV-3027 and CV-3056 are stop valves in the minimum recirculation flow path for the ECCS pumps. If either of these valves were closed when the PCS pressure was above the shutoff head of the ECCS pumps, the pumps could be damaged by running with insufficient flow and thus render both ECCS trains inoperable.

Placing HS-3027A and HS-3027B for CV-3027, and HS-3056A and HS-3056B for CV-3056, in the open position ensures that the valves cannot be inadvertently misaligned or change position as the result of an active failure. These valves are of the type described in Reference 4, which can disable the function of both ECCS trains and invalidate the accident analysis. CV-3027 and CV-3056 are capable of being closed from the control room since the SIRWT must be isolated from the containment during the recirculation phase of a LOCA. A 12 hour Frequency is considered reasonable in view of other administrative controls ensuring that a mispositioned valve is an unlikely possibility.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is appropriate because the valves are operated under procedural control and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

SR 3.5.2.3 verifies CV-3006 is in the open position and that its air supply is isolated. CV-3006 is the shutdown cooling flow control valve located in the common LPSI flow path. The valve must be verified in the full open position to support the low pressure injection flow assumptions used in the accident analyses. The inadvertent misposition of this valve could result in a loss of low pressure injection flow and thus invalidate these flow assumptions. CV-3006 is designed to be held open by spring force and closed by air pressure. To ensure the valve cannot be inadvertently misaligned or change position as the result of a hot short in the control circuit, the air supply to CV-3006 is isolated. Isolation of the air supply to CV-3006 is acceptable since the valve does not require repositioning during an accident.

The 31 day Frequency has been shown to be acceptable through operating practice and the unlikely occurrence of the air supply to CV-3006 being unisolated coincident with a inadvertent valve misalignment event or a hot short in the control circuit.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller damage or other hydraulic component problems is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.5, SR 3.5.2.6, and SR 3.5.2.7

These SRs demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated actuation signal, i.e., on an SIS or RAS, that each ECCS pump starts on receipt of an actual or simulated actuation signal, i.e., on an SIS, and that the LPSI pumps stop on receipt of an actual or simulated actuation signal, i.e., on an RAS. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the Surveillances were performed with the reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability of the equipment and operating experience. The actuation logic is tested as part of the Engineered Safety Feature (ESF) testing, and equipment performance is monitored as part of the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.8

The HPSI Hot Leg Injection motor operated valves and the LPSI loop injection valves have position switches which are set at other than the full open position. This surveillance verifies that these position switches are set properly.

The HPSI Hot leg injection valves are manually opened during the post-LOCA long term cooling phase to admit HPSI injection flow to the PCS hot leg. The open position limit switch on each HPSI hot leg isolation valves is set to establish a predetermined flow split between the HPSI injection entering the PCS hot leg and cold legs.

The LPSI loop injection MOVs open automatically on a SIS signal. The open position limit switch on each LPSI loop injection valve is set to establish the maximum possible flow through that valve. The design of these valves is such that excessive turbulence is developed in the valve body when the valve disk is at the full open position. Stopping the valve travel at slightly less than full open reduces the turbulence and results in increased flow. Verifying that the position stops are properly set ensures that a single low pressure safety injection subsystem is capable of delivering the flow rate required in the safety analysis.

The 18 month Frequency is based on the same factors as those stated above for SR 3.5.2.5, SR 3.5.2.6, and SR 3.5.2.7.

SR 3.5.2.9

Periodic inspection of the containment sump ensures that it is unrestricted and stays in proper operating condition. The 18 month Frequency is based on the need to perform this Surveillance under outage conditions. This Frequency is sufficient to detect abnormal degradation and is confirmed by operating experience.

BASES

REFERENCES

1. FSAR, Section 5.1

2. FSAR, Section 14.17

3. NRC Memorandum to V. Stello, Jr., from R. L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975

4. IE Information Notice No. 87-01, January 6, 1987

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND

The Background section for Bases B 3.5.2, "ECCS - Operating," is applicable to these Bases, with the following modifications.

In MODE 3 with Primary Coolant System (PCS) temperature < 325°F and in MODE 4, an ECCS train is defined as one Low Pressure Safety Injection (LPSI) train. The LPSI flow path consists of piping, valves, and pumps that enable water from the Safety Injection Refueling Water Tank (SIRWT), and subsequently the containment sump, to be injected into the PCS following a Loss of Coolant Accident (LOCA).

APPLICABLE SAFETY ANALYSES

In Mode 3 with PCS temperature < 325°F and in Mode 4 the normal compliment of ECCS components is reduced from that which is available during operations above Mode 3 with PCS temperature ≥ 325°F. The acceptability for the reduced ECCS operational requirements is based on engineering judgement rather than specific analysis and considers such factors as the reduced probability that a LOCA will occur, and the reduced energy stored in the fuel. The reduction in ECCS operational requirements include:

1) Isolation of the Safety Injection Tanks (SITs) since PCS pressure is expected to be reduced below the SIT injection pressure,

2) Reliance on manual safety injection initiation since the automatic Safety Injection Signal (SIS) is not required by the technical specifications below 300°F,

3) Rendering the High Pressure Safety Injection (HPSI) pumps incapable of injecting into the PCS. The HPSI pumps are rendered incapable of injecting into the PCS in accordance with the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System". This action assures that a single mass addition event initiated at a pressure within the limits of LCO 3.4.12 cannot cause the PCS pressure to exceed the 10 CFR 50 Appendix G limit.

BASES

APPLICABLE SAFETY ANALYSES (continued)

At a PCS temperature of 325°F the maximum allowed PCS pressure corresponds to the LTOP setpoint limit which is approximately 800 psia. Below 800 psia postulated piping flaws of critical size are considered unlikely since normal operation at 2060 psia serves as a proof test against ruptures. In addition, since the reactor has been shutdown for a period of time, the decay heat and sensible heat levels are greatly reduced from the full power case.

Although a pipe break in the PCS pressure boundary is considered unlikely, break sizes larger and smaller than approximately 0.1 ft^2 are considered separately when analyzing ECCS response.

For breaks larger than approximately 0.1 ft^2, the event is characterized by a very rapid depressurization of the PCS to near the containment pressure. Due to the reduced temperature and pressure of the PCS, the time to complete blowdown is extended from that assumed in the full power case. During this time, the fuel is cooled by the flow through the core towards the break. Automatic safety injection actuation is not assumed to occur since the pressurizer pressure SIS may be bypassed below 1700 psig. Therefore, operator action is relied upon to initiate ECCS flow. Indication that would alert the operator that a LOCA had occurred include; a loss of pressurizer level, rapid decrease in PCS pressure, increase in containment pressure, and containment high radiation alarm. Since the saturation pressure for 325°F is approximately 100 psia, the LPSI pumps are capable of providing the required heat removal function. When the OPERABLE LPSI pump is being used to fulfill the shutdown cooling function, the PCS pressure is < 300 psia. As such, the rate of PCS blowdown is reduced providing some time to manually realign the OPERABLE LPSI pump to the ECCS mode of operation.

For breaks smaller than approximately 0.1 ft^2, the event is characterized by a slow depressurization of the PCS and a relatively long time for the PCS level to drop below the tops of the hot legs. In MODE 3 with PCS temperature < 325°F and in the upper range of MODE 4 before shutdown cooling is established, the spectrum of smaller break sizes are more limiting than larger breaks in terms of ECCS performance since the PCS could stay above the shutoff head of the LPSI pumps. For these break sizes, sufficient time, well in excess of the recommended 10 minutes attributed for manual operator action, is available to either initiate once through cooling using the PORVs, or by re-establishing HPSI pump injection capability. In either case, the core remains covered and the criteria of 10 CFR 50.46 preserved.

ECCS - Shutdown satisfies Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

In MODE 3 with PCS temperature < 325°F and in MODE 4, an ECCS train is comprised of a single LPSI train. Each LPSI train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the SIRWT and transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to supply water from the SIRWT to the PCS via one LPSI pump and at least one supply header to a cold leg injection nozzle. In the long term, this flow path may be switched to take its supply from the containment sump.

With PCS temperature < 325°F, one LPSI pump is acceptable without single failure consideration, based on the stable reactivity condition of the reactor and the limited core cooling requirements. The High Pressure Safety Injection (HPSI) pumps may therefore be released from the ECCS train requirements. With PCS temperature < 300°F, both HPSI pumps must be rendered incapable of injection into the PCS in accordance with LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The LCO is further modified by a Note that allows a LPSI train to be considered OPERABLE during alignment and operation for shutdown cooling, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation of a LPSI pump in the shutdown cooling mode.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with PCS temperature ≥ 325°F, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 3 with PCS temperature < 325°F and in MODE 4, one OPERABLE ECCS train is acceptable without single failure consideration, based on the stable reactivity condition of the reactor and the limited core cooling requirements.

BASES

APPLICABILITY (continued)

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, "PCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "PCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With no LPSI train OPERABLE, the plant is not prepared to respond to a loss of coolant accident. Action must be initiated Immediately to restore at least one LPSI train to OPERABLE status. The Immediate Completion Time reflects the importance of maintaining an OPERABLE LPSI train and ensures that prompt action is taken to restore the required cooling capacity.

B.1

When the Required Action cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is reasonable, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

The applicable references from Bases 3.5.2 apply.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Safety Injection Refueling Water Tank (SIRWT)

BASES

BACKGROUND

The SIRWT supports the ECCS and the Containment Spray System by providing a source of borated water for Engineered Safety Feature (ESF) pump operation.

The SIRWT supplies two ECCS trains by separate, redundant supply headers. Each header also supplies one train of the Containment Spray System. An air operated isolation valve is provided in each header which isolates the SIRWT from the ECCS after the ESF pump suction has been transferred to the containment sump following depletion of the SIRWT during a Loss of Coolant Accident (LOCA). A separate header is used to supply the Chemical and Volume Control System (CVCS) from the SIRWT. Use of a single SIRWT to supply both trains of the ECCS and Containment Spray System is acceptable since the SIRWT is a passive component, and passive failures are not assumed to occur concurrently with any Design Basis Event during the injection phase of an accident. Not all the water stored in the SIRWT is available for injection following a LOCA; the location of the ESF pump suction piping in the SIRWT will result in some portion of the stored volume being unavailable.

The High Pressure Safety Injection (HPSI) and Low Pressure Safety Injection (LPSI) pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at shutoff head conditions. These lines discharge back to the SIRWT, which vents to the atmosphere. When the suction for the ESF pumps is transferred to the containment sump, the recirculation path must be isolated to prevent is a release of the containment sump contents to the SIRWT. If not isolated, this flow path could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the ESF pumps.

BASES

BACKGROUND (continued)

This LCO ensures that:

a. The SIRWT contains sufficient borated water to support ESF pump operation during the injection phase;

b. Sufficient water volume exists in the containment sump to support continued operation of the ESF pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains subcritical following a LOCA.

Insufficient water inventory in the SIRWT could result in insufficient cooling capacity of the ECCS when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of shutdown margin or excessive boric acid precipitation in the core following a LOCA, as well as excessive stress corrosion of mechanical components and systems inside containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the SIRWT provides a source of borated water to the HPSI, LPSI, and Containment Spray pumps. As such, it provides containment cooling and depressurization, core cooling, 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 Bases B 3.5.2, "ECCS - Operating," and B 3.6.6, "Containment Cooling Systems." These analyses are used to assess changes to the SIRWT in order to evaluate their effects in relation to the acceptance limits.

In MODES 1, 2, and 3 the minimum volume limit of 250,000 gallons is based on two factors:

a. Sufficient deliverable volume must be available to provide at least 20 minutes of full flow from one train of ESF pumps prior to reaching a low level switch over to the containment sump for recirculation; and

b. The containment sump water volume must be sufficient to support continued ESF pump operation after the switch over to recirculation occurs. This sump volume water inventory is supplied by the SIRWT borated water inventory.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Twenty minutes is the point at which approximately 75% of the design flow of one HPSI pump is capable of meeting or exceeding the decay heat boiloff rate.

The SIRWT capacity, alone, is not sufficient to provide adequate Net Positive Suction Head (NPSH) for the HPSI pumps after switch over to the containment sump for the worst case conditions. To assure adequate NPSH for the HPSI pumps, their suction headers are aligned to the discharge of the Containment Spray Pumps (Ref. 2). Restrictions are placed on Containment Spray Pump operation with this alignment to ensure the Containment Spray Pumps have adequate NPSH (Ref. 3).

In MODE 4, the minimum volume limit of 200,000 gallons is based on engineering judgement and considers factors such as:

a. The volume of water transferred from the SIRWT to the PCS to account for the change in PCS water volume during a cooldown from 532°F to 200°F (approximately 17,000 gallons assuming an initial PCS volume of 80,000 gallons); and

b. The minimum SIRWT water volume capable of providing a sufficient level in the containment sump to support LPSI pump operation following a LOCA.

Due to the reduced PCS temperature and pressure requirements in MODE 4, and in recognition that water from the SIRWT used for PCS makeup is available for recirculation following a LOCA, the minimum water volume limit for the SIRWT in MODE 4 is lower than in MODES 1, 2, or 3.

The 1720 ppm limit for minimum boron concentration was established to ensure that, following a LOCA with a minimum level in the SIRWT, the reactor will remain subcritical in the cold condition following mixing of the SIRWT, Safety Injection Tanks, and PCS water volumes. Small break LOCAs assume that all full-length control rods are inserted, except for the control rod of highest worth, which is withdrawn from the core. Large break LOCA analyses assume that all full-length control rods remain withdrawn until the blowdown phase is over. For large break LOCAs, the initial reactor shutdown is accomplished by void formation. The most limiting case occurs at beginning of core life.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The maximum boron limit of 2500 ppm in the SIRWT is based on boron precipitation in the core following a LOCA. With the reactor vessel at saturated conditions, the core dissipates heat by pool nucleate boiling. Because of this boiling phenomenon in the core, the boric acid concentration will increase in this region. If allowed to proceed in this manner, a point will be reached where boron precipitation will occur in the core. Post LOCA emergency procedures direct the operator to establish simultaneous hot and cold leg injection to prevent this condition by establishing a forced flow path through the core regardless of break location. These procedures are based on the minimum time in which precipitation could occur, assuming that maximum boron concentrations exist in the borated water sources used for injection following a LOCA. Boron concentrations in the SIRWT in excess of the limit could result in precipitation earlier than assumed in the analysis.

SIRWT boron concentration and volume also determine the post-LOCA pump pH. Trisodium Phosphate (TSP), stored in the lower region of containment, mixes with the SIRWT water following a LOCA to control pH. Maintaining pH in the proper range is necessary to retain iodine in solution, prevent excessive hydrogen generation, and to prevent potential long term stress corrosion cracking in ESF piping. TSP requirements are addressed in LCO 3.5.5, "Trisodium Phosphate (TSP).".

The upper limit of 100°F and the lower limit of 40°F on SIRWT temperature are the limits assumed in the accident analysis. SIRWT temperature affects the outcome of several analyses. Although the minimum temperature limit of 40°F was selected to maintain a small margin above freezing (32°F), violation of the minimum temperature could result in unacceptable conclusions for some analyses. The upper temperature limit of 100 °F is used in the Containment Pressure and Temperature Analysis. Exceeding this temperature will result in higher containment pressure due to reduced containment spray cooling capacity.

The SIRWT satisfies Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

The SIRWT 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, that the reactor remains subcritical following a DBA, and that an adequate level exists in the containment sump to support ESF pump operation in the recirculation mode.

To be considered OPERABLE, the SIRWT must meet the limits established in the SRs for water volume, boron concentration, and temperature.

APPLICABILITY

In MODES 1, 2, and 3, the SIRWT OPERABILITY requirements are dictated by the ECCS and Containment Spray System OPERABILITY requirements. In MODE 4 the SIRWT OPERABILITY requirements are dictated by ECCS requirements only. As such, the SIRWT must be OPERABLE in MODES 1, 2, 3, and 4.

Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "PCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "PCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With SIRWT boron concentration or borated water temperature not within limits, it must be returned to within limits within 8 hours. In this condition neither the ECCS nor the Containment Spray System can perform their design functions; therefore, prompt action must be taken to restore the tank to OPERABLE condition. The allowed Completion Time of 8 hours to restore the SIRWT to within limits was developed considering the time required to change boron concentration or temperature, and that the contents of the tank are still available for injection.

BASES

ACTIONS (continued)

B.1

With SIRWT borated water volume not within limits, it must be returned to within limits within 1 hour. In this condition, neither the ECCS nor Containment Spray System can perform their design functions; therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which these systems are not required. The allowed Completion Time of 1 hour to restore the SIRWT to OPERABLE status is based on this condition simultaneously affecting multiple redundant trains.

C.1 and C.2

If the SIRWT cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 3.5.4.1

SIRWT borated water temperature shall be verified every 24 hours to be within the limits assumed in the accident analysis. This Frequency has been shown to be sufficient to identify temperature changes that approach either acceptable limit.

SR 3.5.4.2 and SR 3.5.4.3

The minimum SIRWT water volume shall be verified every 7 days. This Frequency ensures that a sufficient initial water supply is available for injection and to support continued ESF pump operation on recirculation. Since the SIRWT volume is normally stable and is provided with a Low Level Alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

SR 3.5.4.2 is modified by a Note which states that it is only required to be met in MODES 1, 2, and 3.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.2 and SR 3.5.4.3 (continued)

SR 3.5.4.3 is modified by a Note which states that it is only required to be met in MODE 4. The required minimum SIRWT water volume is less in MODE 4 since the PCS temperature and pressure are reduced and a significant volume of water is transferred from the SIRWT to the PCS during MODE 4 to account for primary coolant shrinkage.

SR 3.5.4.4

Boron concentration of the SIRWT shall be verified every 31 days to be within the required range. This Frequency ensures that the reactor will remain subcritical following a LOCA. Further, it ensures that the resulting sump pH will be maintained in an acceptable range such that boron precipitation in the core will not occur earlier than predicted and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized.

Since the SIRWT volume is normally stable, a 31 day sampling Frequency is appropriate and has been shown through operating experience to be acceptable.

REFERENCES

1. FSAR, Chapter 6 and Chapter 14

2. Design Basis Document (DBD) 2.02, "High-Pressure Safety Injection System," Section 3.3.1

3. EOP 4.0, Loss of Coolant Accident

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Trisodium Phosphate (TSP)

BASES

BACKGROUND

TSP baskets are is placed on the floor (590 ft elevation) in the containment building to ensure that iodine, which may be dissolved in the recirculated primary cooling water following a Loss of Coolant Accident (LOCA), remains in solution (Ref. 1). Recirculation of the water for core cooling and containment spray provides mixing to achieve a uniform neutral pH. TSP also helps inhibit Stress Corrosion Cracking (SCC) of austenitic stainless steel components in containment during the recirculation phase following an accident.

Fuel that is damaged during a LOCA will release iodine in several chemical forms to the reactor coolant and to the containment atmosphere. A portion of the iodine in the containment atmosphere is washed to the sump by containment sprays. The Safety Injection Refueling Water Tank water is borated for reactivity control. This borated water, if left untreated, would cause the sump solution to be acidic. In a low pH (acidic) solution, dissolved iodine will be converted to a volatile form. The volatile iodine will evolve out of solution into the containment atmosphere, significantly increasing the levels of airborne iodine. The increased levels of airborne iodine in containment contribute to the radiological releases and increase the consequences from the accident due to containment atmosphere leakage.

After a LOCA, the components of the safety injection and containment spray systems will be exposed to high temperature borated water. Prolonged exposure to hot untreated sump water combined with stresses imposed on the components can cause SCC. The rate of SCC is a function of stress, oxygen and chloride concentrations, pH, temperature, and alloy composition of the components. High temperatures and low pH, which would be present after a LOCA, tend to promote SCC. This can lead to the failure of necessary safety systems or components.

BASES

BACKGROUND (continued)

Adjusting the pH of the recirculation solution to levels above 7.0 prevents a significant fraction of the dissolved iodine from converting to a volatile form. The higher pH thus decreases the level of airborne iodine in containment and reduces the radiological consequences from containment atmosphere leakage following a LOCA. Maintaining the solution pH above 7.0 also reduces the occurrence of SCC of austenitic stainless steel components in containment. Reducing SCC reduces the probability of failure of components.

The hydrated form (45-57% moisture) of TSP is used because of the high humidity in the containment building during normal operation. Since the TSP is hydrated, it is less likely to absorb large amounts of water from the humid atmosphere and will undergo less physical and chemical change than the anhydrous form of TSP.

APPLICABLE SAFETY ANALYSES

The LOCA radiological consequences analysis takes credit for iodine retention in the sump solution based on the recirculation water pH being ≥ 7.0. The radionuclide releases from the containment atmosphere and the consequences of a LOCA would be increased if the pH of the recirculation water were not adjusted to 7.0 or above.

The containment hydrogen concentration analysis used in the evaluation of the Maximum Hypothetical Accident (MHA) assumes the pH of the containment sump water is between 7.0 and 8.0. The acceptance criteria of the MHA includes a containment lower flammability limit of 4 volume percent for hydrogen. Containment sump water with a pH greater than 8.0 could result in excess hydrogen generation in containment and invalidate the conclusions of the MHA.

TSP satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The quantity of TSP placed in containment is designed to adjust the pH of the sump water to be between 7.0 and 8.0 after a LOCA. A pH > 7.0 is necessary to prevent significant amounts of iodine released from fuel failures and dissolved in the recirculation water from converting to a volatile form and evolving into the containment atmosphere. Higher levels of airborne iodine in containment may increase the release of radionuclides and the consequences of the accident. A pH > 7.0 is also necessary to prevent SCC of austenitic stainless steel components in containment. SCC increases the probability of failure of components.

BASES

LCO (continued)

The pH needs to remain < 8.0 to remain within the assumptions of the analysis for post-LOCA Hydrogen concentration in the containment.

The minimum acceptable amount of TSP is that weight which will ensure a sump solution pH ≥ 7.0 after a LOCA, with the maximum amount of water at the minimum initial pH possible in the containment sump; a maximum acceptable amount of TSP is that weight which will ensure a sump solution pH of ≤ 8.0 with a minimum amount of water at a maximum initial pH.

The TSP is stored in wire mesh baskets placed inside the containment at the 590 ft elevation. Any quantity of TSP between 8,300 and 11,000 lb. will result in a pH in the desired range.

APPLICABILITY

In MODES 1, 2, and 3, the PCS is at elevated temperature and pressure, providing an energy potential for a LOCA. The potential for a LOCA results in a need for the ability to control the pH of the recirculated coolant.

In MODES 4, 5, and 6, the potential for a LOCA is reduced or nonexistent, and TSP is not required.

ACTIONS

A.1

If it is discovered that the TSP in the containment building is not within limits, action must be taken to restore the TSP to within limits.

The Completion Time of 72 hours is allowed for restoring the TSP within limits, where possible, because 72 hours is the same time allowed for restoration of other ECCS components.

B.1 and B.2

If the TSP cannot be restored within limits within the Completion Time of Required Action A.1, the plant must be brought to a MODE in which the LCO does not apply. The specified Completion Times for reaching MODES 3 and 4 are those used throughout the Technical Specifications; they were chosen to allow reaching the specified conditions from full power in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

Periodic determination of the mass of TSP in containment must be performed due to the possibility of leaking valves and components in the containment building that could cause dissolution of the TSP during normal operation. A Frequency of 18 months is required to determine that ≥ 8,300 lbs and ≤ 11,000 lbs are contained in the TSP baskets. This requirement ensures that there is an adequate mass of TSP to adjust the pH of the post LOCA sump solution to a value ≥ 7.0 and ≤ 8.0.

The periodic verification is required every 18 months, since determining the mass of the TSP baskets is only feasible during outages, and normal fuel cycles are scheduled for 18 months. Operating experience has shown this Surveillance Frequency acceptable due to the margin in the mass of TSP placed in the containment building.

SR 3.5.5.2

Periodic testing is performed to ensure the solubility and buffering ability of the TSP after exposure to the containment environment. Satisfactory completion of this test assures that the TSP in the baskets is "active."

Adequate solubility is verified by submerging a representative sample of TSP from one of the baskets in containment in un-agitated borated water heated to a temperature representing post-LOCA conditions; the TSP must completely dissolve within a 4 hour period. The test time of 4 hours is to allow time for the dissolved TSP to naturally diffuse through the un-agitated test solution. Agitation of the test solution during the solubility verification is prohibited, since an adequate standard for the agitation intensity (other than no agitation) cannot be specified. The agitation due to flow and turbulence in the containment sump during recirculation would significantly decrease the time required for the TSP to dissolve.

Adequate buffering capability is verified by a measured pH of the sample solution, following the solubility verification, between 7.0 and 8.0. The sample is cooled and thoroughly mixed prior to measuring pH.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.2 (continued)

The quantity of the TSP sample, and quantity and boron concentration of the water are chosen to be representative of post-LOCA conditions.

A sampling Frequency of every 18 months is specified. Operating experience has shown this Surveillance Frequency to be acceptable.

REFERENCES

1. FSAR, Section 6.4

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of a concrete structure lined with steel plate, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a Loss of Coolant design basis 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, and a shallow dome roof. The foundation slab is reinforced with conventional mild-steel reinforcing. The internal pressure loads on the base slab are resisted by both the external soil pressure and the strength of the reinforced concrete slab. The cylinder wall is prestressed with a post tensioning system in the vertical and horizontal directions. The dome roof is prestressed utilizing a three way post tensioning system. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The concrete structure is required for structural integrity of the containment under Design Basis Accident (DBA) conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 and SR 3.6.1.3 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B for Type A tests and Option A for Type B and C tests, as modified by approved exemptions.

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

BASES

BACKGROUND (continued)

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. The equipment hatch is properly closed and sealed.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a release of radioactive material within containment are a Loss of Coolant Accident (LOCA), a Main Steam Line Break (MSLB), and a control rod ejection accident (Ref. 1). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.10% of containment air weight per day (Ref. 3). This leakage rate is defined in 10 CFR 50, Appendix J, as L_a: the maximum allowable containment leakage rate at the calculated maximum peak containment pressure (P_a) of 53 psig, which results from the limiting design basis LOCA. (Ref. 2). For the Palisades Nuclear Plant, the calculated maximum peak containment pressure results from a MSLB accident. However, since the limiting accident from an offsite dose perspective is a LOCA, this pressure is used as P_a. The P_a value of 53 psig represents the analytical value found in Reference 1, rounded up to the next whole number.

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required 10 CFR 50, Appendix J leakage test. At this time, the applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

BASES

LCO (continued)

Individual leakage rates specified for the containment air lock (LCO 3.6.2) and purge valves which have resilient seals (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABILITY during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring, during periods when containment is inoperable, is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and Type A leakage rate test requirements of the Containment Leak Rate Testing Program. Failure to meet air lock and containment isolation valve leakage limits does not invalidate the acceptability of the overall Type A determination. As left leakage prior to the first startup after performing a required leakage test is required to be $\leq 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leak Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

SR 3.6.1.2

This SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Structural Integrity Surveillance Program.

SR 3.6.1.3

Maintaining the containment OPERABLE requires compliance with the Type B and C leakage rate test requirements of 10 CFR 50, Appendix J, Option A (Ref. 4), as modified by approved exemptions. Testing is performed at pressures $\geq$ 55 psig. Failure to meet air lock and containment isolation valve leakage limits does not invalidate the acceptability of the overall Type A determination. As left leakage prior to the first startup after performing a required 10 CFR 50, Appendix J, Option A, leakage test is required to be $< 0.6\ L_a$ for combined Type B and C 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 Appendix J, Option A, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3 (continued)

SR 3.6.1.3 is modified by a Note which states that local leak tests shall be performed at pressures ≥ 55 psig. This value corresponds to the design pressure of the containment and bounds the maximum expected internal pressure resulting from an MSLB or design basis LOCA.

REFERENCES

1. FSAR, Chapter 14
2. FSAR, Section 14.18
3. FSAR, Section 5.8
4. 10 CFR 50, Appendix J

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.

Two air locks provide access into the containment. Each air lock is nominally a right circular cylinder, with a door at each end. The personnel air lock doors are 3 foot, 6 inches by 6 foot, 8 inches. The emergency escape air lock doors are 30 inches in diameter. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local 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).

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 plant safety analysis.

BASES

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a Loss of Coolant Accident (LOCA), a Main Steam Line Break (MSLB) and a control rod ejection accident (Ref. 1). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.10% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option A, as L_a : the maximum allowable containment leakage rate at the calculated maximum peak containment pressure (P_a). For a LOCA, the calculated maximum peak containment pressure is approximately 53 psig. For an MSLB, the calculated maximum peak containment pressure is approximately 54 psig. However, to ensure sufficient margin and to bound all DBAs, Type B leakage rate testing is performed at or above the containment design pressure of 55.0 psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2).

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 OPERABLE 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.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by three notes. The first note 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 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, even if this door has been locked to comply with ACTIONS. This means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable because of 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. A third Note has been included that requires entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when leakage results in exceeding the overall containment leakage limit.

BASES

ACTIONS (continued)

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

With one air lock door inoperable in one or more containment air locks, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed an OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception provided by 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.

BASES

ACTIONS

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

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 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 was entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

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

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

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

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. If the overall containment leakage rate exceeds the limits of LCO 3.6.1, the conditions of that LCO must be entered in accordance with Actions Note 3. 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. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of 10 CFR 50, Appendix J, Option A (Ref. 3), as modified by approved exemptions. For the purpose of air lock testing in accordance with 10 CFR 50, Appendix J, "Containment OPERABILITY" is equivalent to "Containment Integrity."

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. Subsequent amendments to the Technical Specifications revised the acceptance criteria for overall Type B and C leakage limits and provided new acceptance criteria for the personnel air lock doors and the emergency air lock doors (Ref. 2). The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. Leak rate tests, other than the personnel air lock doors between the seals test, are performed at pressure ≥ 55 psig. The Frequency is required by 10 CFR 50, Appendix J, Option A, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

Two exemptions to the requirements of 10 CFR 50, Appendix J have been granted for the containment air locks. The exemption granted by letter dated December 6, 1989 provides partial relief from the requirement of Paragraph III.D.2.(b)(ii) to leak test, at or above the calculated design basis accident peak containment pressure (P_a), containment air locks which were opened during a period when containment integrity was not required. This exemption permits the substitution of a between-the-seal leak test at a reduced pressure, but not less than 10 psig, provided that no maintenance, modification, or other activity has been performed which could affect the sealing capability of the air locks.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1 (continued)

The exemption granted by letter dated September 30, 1997 applies only to the emergency escape air lock and provides partial relief from the requirement of Paragraph III.D.2.(b)(ii) and Paragraph III.D.2.(b)(iii). The requirement of Paragraph III.D.2.(b)(ii) is discussed above. Paragraph III.D.2.(b)(iii) requires air locks opened during periods when containment integrity is required to undergo a full air lock pressure test within 3 days after being opened. This exemption permits the performance of a door seal contact verification check in lieu of the final pressure test following the opening of the emergency escape air lock doors for post-test restoration or seal adjustment. This exemption does not affect compliance with the requirement to perform a full pressure air lock test at 6 month intervals, or the requirement to perform a full pressure air lock test within 72 hours of opening either air lock door during periods when containment integrity is required.

The SR has been modified by four 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 of SR 3.6.1.3. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate. Note 3 clarifies that iterative pressure testing of the emergency escape air lock is not required when the air lock doors are opened solely for the purpose of strongback removal and performance of the seal contact check. Note 4 ensures that air lock testing, other that door seal testing, is performed at a pressure ≥ 55 psig consistent with other Type B and C tests.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 into and out of 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. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the airlock is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 18 months. The 18 month frequency is based on the need to perform this Surveillance under the conditions that apply during plant outage, and the potential for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power.

The 18 month Frequency for the interlock is justified based on generic operating experience. The Frequency is based on engineering judgment and is considered adequate given that the interlock is not normally challenged during use of the airlock.

REFERENCES

1. FSAR, Chapter 14
2. FSAR, Section 5.8
3. 10 CFR 50, Appendix J

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves and devices form part of the containment pressure boundary and provide a means for isolating penetration flow paths. 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 analysis. One of these barriers may be a closed system.

Containment isolation occurs upon receipt of a Containment High Pressure (CHP) signal or a Containment High Radiation (CHR) signal. However, not all containment isolation valves are actuated by both signals. The signals close automatic containment isolation valves in fluid penetrations not required for operation of Engineered Safety Feature systems in order to prevent leakage of radioactive material. Other penetrations are isolated by the use of valves or check valves in the closed position, or blind flanges. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated in the event of a release of radioactive material to containment atmosphere from the Primary Coolant System (PCS) following a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves and devices help ensure that containment is isolated within the time limits assumed in the safety analysis. Therefore, the OPERABILITY requirements provide assurance that the containment leakage limits assumed in the accident analysis will be not exceeded in a DBA.

BASES

BACKGROUND (continued)

The 8 inch purge exhaust valves are designed for purging the containment atmosphere to the stack while introducing filtered makeup, through the 12 inch air room supply valves from the outside, when the plant is shut down during refueling operations and maintenance. The purge exhaust valves and air room supply valves are air operated isolation valves located outside the containment. These valves are operated manually from the control room. These valves will close automatically upon receipt of a CHP or CHR signal. The air operated valves fail closed upon a loss of air. These valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, these valves are locked closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Open purge exhaust or air room supply valves, following an accident that releases contamination to the containment atmosphere, would cause a significant increase in the containment leakage rate.

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 analysis of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a Loss of Coolant Accident (LOCA), a Main Steam Line Break (MSLB), and a control rod ejection accident. In the analysis for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized. The safety analysis assumes that the purge exhaust and air room supply valves are closed at event initiation.

The DBA analysis assumes that, within 25 seconds after receiving a CHP or CHR signal each automatic power operated valve is closed and containment leakage terminated except for the design leakage rate, L_a.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the design of the containment purge valves. Two valves in series on each line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. Both isolation valves on the 8 inch and 12 inch lines are pneumatically operated spring closed valves.

The 8 inch purge exhaust and 12 inch air room supply valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain locked closed during MODES 1, 2, 3, and 4. In this case, the single failure criterion remains applicable to the containment purge valves due to the potential for 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 10 CFR 50.36(c)(2).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valve safety function is related to minimizing the loss of primary 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 upon receipt of a CHP or CHR signal as appropriate. The purge exhaust and air room supply valves must be locked closed. The valves covered by this LCO are listed with their associated stroke times in the FSAR (Ref. 1).

The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves or devices are those listed in Reference 1.

The purge exhaust and air room supply valves with resilient seals must meet the same leakage rate testing requirements as other Type C tested containment isolation valves addressed by LCO 3.6.1, "Containment."

BASES

LCO (continued)

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of primary coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by four notes. Note one allows isolated penetration flow paths, except for 8 inch exhaust and 12 inch air room supply purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the fact that the 8 inch purge exhaust valves and the 12 inch air room supply valves may be unable to close in the environment following a LOCA and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, these valves may not be opened under administrative controls.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by a third Note, which ensures that appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

A fourth Note has been added that requires entry into the applicable Conditions and Required Actions of LCO 3.6.1 when leakage results in exceeding the overall containment leakage limit.

BASES

ACTIONS

A.1 and A.2 (continued)

In the event one containment isolation valve in one or more penetration flow paths is inoperable (except for purge exhaust or air room supply valves), the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations 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 the 4 hour Completion Time. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification, through a system walkdown, that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low.

For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides appropriate actions.

BASES

ACTIONS (continued)

A.1 and A.2

Required Action A.2 is modified by a Note that 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. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is small.

B.1

With two containment isolation valves in one or more penetration flow paths inoperable (except for purge exhaust valve or air room supply valve not locked closed), the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.

In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated.

The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative controls and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable, considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4. In the event the affected penetration 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 is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate considering 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 2. 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 a Note that 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. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

D.1

The purge exhaust and air room supply isolation valves have not been qualified to close following a LOCA and are required to be locked closed. If one or more of these valves is found not locked closed, the potential exists for the valves to be inadvertently opened. One hour is provided to lock closed the affected valves. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining these valves closed.

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

This SR ensures that the 8 inch purge exhaust and 12 inch air room supply valves are locked closed as required. If a valve is open, or closed but not locked, in violation of this SR, the valve is considered inoperable. Valves may be locked closed electrically, mechanically, or by other physical means. These valves may be unable to close in the environment following a LOCA. Therefore, each of the valves is required to remain closed during MODES 1, 2, 3, and 4. The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2

This SR requires verification that each manual containment isolation valve and blind flange located outside containment, and not locked, sealed, or otherwise secured in position, 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 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, that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. Containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed or otherwise secured in position, 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 the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate, since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. Containment isolation valves that are open under administrative controls are not required to meet the SR during the time that they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

The 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, and 3 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.4

Verifying that the isolation time of each automatic power operated containment isolation valve 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 analysis. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SR 3.6.3.5

For containment 8 inch purge exhaust and 12 inch air room supply valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option A (Ref. 3), is required to ensure the valves are physically closed (SR 3.6.3.1 verifies the valves are locked closed). Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation and the importance of maintaining this penetration leak tight (due to the direct path between containment and the environment), a Frequency of 184 days was established as part of the NRC resolution of Generic Issue B-20, "Containment Leakage Due to Seal Deterioration" (Ref. 4) as specified in the Safety Evaluation for Amendment No. 90 to the Facility Operating License.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.6

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures each automatic containment isolation valve will actuate to its isolation position on an actual or simulated actuation signal, i.e., CHP or CHR. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency was developed considering it is prudent that this SR be performed only during a plant outage, since isolation of penetrations would eliminate cooling water flow and disrupt normal operation of many critical components. Operating experience has shown that these components usually pass this SR when performed on the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 5.8
2. FSAR, Section 6.7.2
3. 10 CFR 50, Appendix J
4. Generic Issue B-20

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 Main Steam Line Break (MSLB).

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. 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 for determining the maximum containment internal pressure are the LOCA and MSLB. An MSLB at 0% RTP with the MSIVs open results in the highest calculated internal containment pressure of 54 psig, which is below the internal design pressure of 55 psig. The value of 54 psig represents the analytical value presented in Reference 1, rounded up to the next whole number. The postulated DBAs are analyzed assuming degraded containment Engineered Safety Feature (ESF) systems (i.e., assuming the limiting single active failure, resulting in the loss of two Containment Spray pumps since a common mode failure disables two of the three pumps. While the maximum containment internal pressure results from an MSLB, the licensing basis dose limitations are based on the LOCA (see the Bases for 3.6.1, "Containment," for a discussion on containment pressures resulting from a LOCA).

The initial pressure condition used in the containment analysis was 15.7 psia (1.0 psig) in MODES 1 and 2 and 16.2 psia (1.5 psig in MODES 3 and 4). The LCO limits of 1.0 psig in MODES 1 and 2, and 1.5 psig in MODES 3 and 4 ensures that, in the event of an accident, the maximum accident design pressure for containment, 55 psig, is not exceeded.

A higher containment pressure limit is allowed in MODES 3 and 4 where the reactor is not critical and the resulting heat addition to containment in a DBA is lower.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The external design pressure of the containment shell is 3 psig. This value is approximately 0.5 psig greater than the maximum external pressure that could be developed if the containment were sealed during a period of low barometric pressure and high temperature and, subsequently, the containment atmosphere were cooled with a concurrent major rise in barometric pressure. Vacuum breakers are, therefore, not provided and no minimum containment pressure specification is required.

Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

Maintaining containment pressure 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. Two limits for containment pressure are provided to reflect the analyses which allow for a higher containment pressure when the reactor is not critical due to less heat input to containment in the event of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analysis are maintained, the LCO is applicable in MODES 1, 2, 3, and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, containment pressure must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

BASES

ACTIONS (continued)

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that operation remains within the limits assumed in the accident analyses. The 12 hour Frequency of this SR was developed after taking into consideration operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition. The limit of 1.0 psig for MODES 1 and 2, 1.5 psig for MODES 3 and 4 are the actual limits used in the accident analysis and do not account for instrument inaccuracies.

REFERENCES

1. FSAR, Section 14.18

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 Main Steam Line Break (MSLB).

Containment air temperature is a process variable that is monitored and controlled. The containment average air temperature limit is derived from the input conditions used in the containment accident analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during plant operations. The total amount of energy to be removed from containment by the Containment Spray and Cooling systems during post accident conditions is dependent on 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, resulting in a higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis (Ref. 1). Operation with containment average air 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 analysis for containment. The accident analyses and evaluations considered both LOCAs and MSLBs for determining the maximum peak containment pressures and temperatures. The worst case MSLB generates larger mass and energy releases than the worst case LOCA. Thus, the MSLB event bounds the LOCA event from the containment peak pressure and temperature standpoint.

The initial pre-accident temperature inside containment was assumed to be 140°F (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The initial containment average air temperature condition of 140°F resulted in a maximum vapor temperature in containment of 399°F. This value represents the analytical value presented in Reference 3, rounded up to the next highest number. This exceeds the containment building design temperature of 283°F. The effect on the containment structure is negligible due to the short period of time the temperature exceeds the design value.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident pressure is maintained below the containment design pressure. As a result, the ability of containment to perform its function is ensured.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the 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.

BASES

ACTIONS (continued)

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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. The 140°F limit is the actual limit assumed for the accident analyses and does not account for instrument inaccuracies. Instrument uncertainties are accounted for in the surveillance procedure. The 24 hour Frequency of this SR is considered acceptable based on the observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment).

REFERENCES

1. FSAR, Section 5.8
2. FSAR, Section 14.18
3. FSAR, Table 14.18.2-3

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Air Recirculation and 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 reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA). The Containment Spray and Containment Air Recirculation and Cooling systems are designed to the requirements of the Palisades Nuclear Plant design criteria (Ref. 1).

The Containment Air Recirculation and 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 systems are arranged with two spray pumps and one air cooler fan powered from one diesel generator, and with one spray pump and three air cooler fans powered from the other diesel generator. The Containment Spray System was originally designed to be redundant to the Containment Air Coolers (CACs) and fans. These systems were originally designed such that either two containment spray pumps or three CACs could limit containment pressure to less than design. However, the current safety analyses take credit for one containment spray pump when evaluating cases with three CACs, and for one air cooler fan in cases with two spray pumps.

To address this dependency between the Containment Spray System and the Containment Air Recirculation and Cooling System the title of this Specification is "Containment Cooling Systems," and includes both systems. The LCO is written in terms of trains of containment cooling. One train of containment cooling is associated with Diesel Generator 1-1 and includes Containment Spray Pumps P-54B and P-54C, and Air Cooler Fan V-4A. The other train of containment cooling is associated with Diesel Generator 1-2 and includes Containment Spray Pump P-54A along with CACs VHX-1, VHX-2, and VHX-3 and their associated safety related fans, V-1A, V-2A, and V-3A .

BASES

BACKGROUND (continued)

If reliance is placed solely on one spray pump and three CACs, at least two service water pumps must be OPERABLE to provide the necessary service water flow to assure OPERABILITY of the CACs. Additional details of the required equipment and its operation is discussed with the containment cooling system with which it is associated.

Containment Spray System

The Containment Spray System consists of three half-capacity (50%) motor driven pumps, spray headers, two full sets of full capacity (100%) nozzles, valves, and piping, two full capacity (100%) pump suction lines from the Safety Injection and Refueling Water Tank (SIRWT) and the containment sump with the associated piping, valves, power sources, instruments, and controls. The SIRWT supplies borated water to the containment spray during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the SIRWT to the containment sump.

The Containment Spray System provides a spray of cold borated water into the upper regions of containment to reduce the containment pressure and temperature during a DBA. In addition, the Containment Spray System in conjunction with the use of trisodium phosphate (LCO 3.5.5, "Trisodium Phosphate,") serve to remove iodine which may be released following an accident. The SIRWT 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 shutdown cooling heat exchangers. Two containment spray pumps will meet the capacity requirements in the event of a DBA.

The Containment Spray System is actuated either automatically by a Containment High Pressure (CHP) signal or manually. An automatic actuation opens the containment spray header isolation valves, starts the three containment spray pumps, and begins the injection phase.
A manual actuation of the Containment Spray System is available on the main control board to begin the same sequence. The injection phase continues until an SIRWT Level Low signal is received. The Low Level signal for the SIRWT generates a Recirculation Actuation Signal (RAS) that aligns valves from the containment spray pump suction to the containment sump. The Containment Spray System in recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

BASES

BACKGROUND

Containment Spray System (continued)

The containment spray pumps also provide a required support function for the High Pressure Safety Injection pumps as described in the Bases for specification 3.5.2. The High Pressure Safety Injection pumps alone may not have adequate NPSH after a postulated accident and the realignment of their suctions from the SIRWT to the containment sump. Provision is made to manually provide flow from the discharge of the containment spray pumps to the suction of the High Pressure Safety Injection pumps after the change to recirculation mode has occurred. The additional suction pressure ensures that adequate NPSH is available for the High Pressure Safety Injection pumps.

Containment Air Recirculation and Cooling System

The Containment Air Recirculation and Cooling System includes four air handling and cooling units, referred to as the Containment Air Coolers (CACs), which are located entirely within the containment building. Three of the CACs (VHX-1, VHX-2, and VHX-3) are safety related coolers and are cooled by the critical service water. The fourth CAC (VHX-4) is not taken credit for in an DBA for maintaining containment temperature within limit, but is used during normal operation along with the three CACs to maintain containment temperature below design limits. The fan associated with VHX-4, V-4A, is assumed in the safety analysis as assisting in the containment atmosphere mixing function.

The DG which powers the fans associated with VHX-1, VHX-2, and VHX-3 (V-1A, V-2A and V-3) also powers two service water pumps. This is necessary because if reliance is placed solely on the train with one spray pump and three CACs, at least two service water pumps must be OPERABLE to provide the necessary service water flow to assure OPERABILITY of the CACs.

BASES

BACKGROUND

Containment Air Recirculation and Cooling System (continued)

Each CAC has two vaneaxial fans with direct connected motors which draw air through the cooling coils. Both of these fans are normally in operation, but only one fan and motor for each CAC is rated for post DBA operation. The post-DBA rated "safety related" fan units, V-1A, V-2A, V-3A, and V-4A, serve not only to provide forced flow for the associated cooler, but also provide mixing of the containment atmosphere. A single operating safety related fan unit will provide enough air flow to assure that there is adequate mixing of unsprayed containment areas to assure the assumed iodine removal by the containment spray. The fan units also support the functioning of the hydrogen recombiners, as discussed in the Bases for LCO 3.6.7, "Hydrogen Recombiners." In post accident operation following a SIS, all four Containment air coolers are designed to change automatically to the emergency mode.

The CACs are automatically changed to the emergency mode by a Safety Injection Signal (SIS). This signal will trip the normal rated fan motor in each unit, open the high-capacity service water discharge valve from VHX-1, VHX-2 , and VHX-3, and close the high-capacity service water supply valve to VHX-4. The test to verify the service water valves actuate to their correct position upon receipt of an SIS signal is included in the surveillance test performed as part of Specification 3.7.8, "Service Water System." The safety related fans are normally in operation and only receive an actuation signal through the DBA sequencers following an SIS in conjunction with a loss of offsite power. This actuation is tested by the surveillance which verifies the energizing of loads from the DBA sequencers in Specification 3.8.1, "AC Sources-Operating."

BASES

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Air Recirculation System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered relative to containment temperature and pressure are the Loss of Coolant Accident (LOCA) and the Main Steam Line Break (MSLB). The DBA 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 LOCA DBA is analyzed, in regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train of Containment Cooling rendered inoperable (Ref. 6). The postulated MSLB DBA is analyzed, in regard to containment ESF systems, assuming the loss of two containment spray pumps, which is the worst case single active failure (Ref. 7).

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure and the peak containment vapor temperature are within the intent of the design basis. (See the Bases for Specifications 3.6.4, "Containment Pressure," and 3.6.5, "Containment Air Temperature," for a detailed discussion.) The analyses and evaluations considered a range of power levels and equipment configurations as described in Reference 2. The peak containment pressure case is the 0% power MSLB with initial (pre-accident) conditions of 140°F and 16.2 psia. The peak temperature case is the 102% power MSLB with initial (pre-accident) conditions of 140°F and 15.7 psia. The analyses also assume a response time delayed initiation in order to provide conservative peak calculated containment pressure and temperature responses.

The external design pressure of the containment shell is 3 psig. This value is approximately 0.5 psig greater than the maximum external pressure that could be developed if the containment were sealed during a period of low barometric pressure and high temperature and, subsequently, the containment atmosphere was cooled with a concurrent major rise in barometric pressure.

The modeled Containment Cooling System actuation from the containment analysis is based on a response time associated with exceeding the Containment High Pressure setpoint to achieve full flow through the CACs and containment spray nozzles. The spray lines within containment are maintained filled to the 735 ft elevation to provide for rapid spray initiation. The Containment Cooling System total response time of < 60 seconds includes diesel generator startup (for loss of offsite power), loading of equipment, CAC and containment spray pump startup, and spray line filling.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The performance of the Containment Spray System for post accident conditions is given in Reference 3. The performance of the Containment Air Coolers is given in Reference 4. The result of the analysis is that each train of containment cooling can provide 100% of the required peak cooling capacity during the post accident condition.

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

During a DBA, a minimum of one containment cooling train is required to maintain the containment peak pressure and temperature below the design limits (Ref. 2). One train of containment cooling is associated with Diesel Generator 1-1 and includes Containment Spray Pumps P-54B and P-54C, and air cooler fan V-4A. The other train of containment cooling is associated with Diesel Generator 1-2 and includes Containment Spray Pump P-54A along with CACs VHX-1, VHX-2, and VHX-3 and their associated safety related fans, V-1A, V-2A, and V-3A. To ensure that these requirements are met, two trains of containment cooling must be OPERABLE. Therefore, in the event of an accident, the minimum requirements are met, assuming the worst case single active failure occurs.

The Containment Spray System portion of containment cooling train includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the SIRWT upon an ESF actuation signal and automatically transferring suction to the containment sump.

The Containment Air Recirculation and Cooling System portion of the containment cooling train which must be OPERABLE includes the three safety related air coolers which each consist of four cooling coil banks, the safety related fan which must be in operation to be OPERABLE, gravity-operated fan discharge dampers, instruments, and controls to ensure an OPERABLE flow path.

CAC fans V-1A, V-2A, V-3A, and V-4A must be in operation to be considered OPERABLE. These fans only receive a start signal from the DBA sequencer; they are assumed to be in operation, and are not started by either a CHP or an SIS signal.

BASES

APPLICABILITY

In MODES 1, 2, and 3, 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 containment cooling trains.

In MODES 4, 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 and Containment Cooling systems are not required to be OPERABLE in MODES 4, 5 and 6.

ACTIONS

A.1

With one or more trains of containment cooling inoperable, but at least 100% of the required post accident containment cooling capability available, the inoperable containment cooling components must be restored to OPERABLE status within 72 hours.

This condition allows either 1) any two containment spray pumps to be inoperable (even if they are supplied from different electrical trains of power), or 2) the three required CACs and one containment spray pump to be inoperable, as long as two containment spray pumps and one cooling fan, or the three required CACs and one containment spray pump are OPERABLE. If two spray pumps are inoperable (thereby placing reliance on the remaining spray pump and the CACs), then at least two service water pumps must be OPERABLE to provide the necessary service water flow to assure OPERABILITY of the CACs.

The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by the other Containment Cooling train and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action and associated Completion Time of this LCO 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 4 within 30 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 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves, excluding check valves, in the Containment Spray System provides assurance that the proper flow path exists for Containment Spray System operation. This SR also does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct positions prior to being secured. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned, are in the correct position.

SR 3.6.6.2

Operating each safety related Containment Air Cooler fan unit for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. The 31 day Frequency was developed considering the known reliability of the fan units and controls, the two train redundancy available, and the low probability of a significant degradation of the containment cooling train occurring between surveillances.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3

Verifying the containment spray header is full of water to the 735 ft elevation minimizes the time required to fill the header. This ensures that spray flow will be admitted to the containment atmosphere within the time frame assumed in the containment analysis. The 31 day Frequency is based on the static nature of the fill header and the low probability of a significant degradation of the water level in the piping occurring between surveillances.

SR 3.6.6.4

Verifying a total service water flow rate of ≥ 4800 gpm to CACs VHX-1, VHX-2, and VHX-3, when aligned for accident conditions, provides assurance the design flow rate assumed in the safety analyses will be achieved (Ref. 8). Also considered in selecting this Frequency were the known reliability of the cooling water system, the two train redundancy, and the low probability of a significant degradation of flow occurring between surveillances.

SR 3.6.6.5

Verifying that each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 5).

Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.6 and SR 3.6.6.7

SR 3.6.6.6 verifies each automatic containment spray valve actuates to its correct position upon receipt of an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. SR 3.6.6.7 verifies each containment spray pump starts automatically on an actual or simulated actuation signal. The 18 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power.

Operating experience has shown that these components usually pass the Surveillances when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Where the surveillance of containment sump isolation valves is also required by SR 3.5.2.5, a single surveillance may be used to satisfy both requirements.

SR 3.6.6.8

This SR verifies each containment cooling fan actuates upon receipt of an actual or simulated actuation signal. The 18 month Frequency is based on engineering judgement and has been shown to be acceptable through operating experience. See SR 3.6.6.6 and SR 3.6.6.7, above, for further discussion of the basis for the 18 month Frequency.

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. Performance of this SR demonstrates that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, a test at 10 year intervals is considered adequate to detect obstruction of the spray nozzles.

BASES

REFERENCES

1. FSAR, Section 5.1
2. FSAR, Section 14.18
3. FSAR, Sections 6.2
4. FSAR, Section 6.3
5. ASME, Boiler and Pressure Vessel Code, Section XI
6. FSAR, Table 14.18.1-3
7. FSAR, Table 14.18.2-1
8. FSAR, Table 9-1

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Hydrogen Recombiners

BASES

BACKGROUND

The function of the hydrogen Recombiners is to eliminate the potential breach of containment due to a sudden hydrogen oxygen reaction. Per 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and the Palisades Nuclear Plant design criteria (Ref. 2), hydrogen recombiners are required to reduce the hydrogen concentration in the containment following a Loss of Coolant Accident (LOCA) or Main Steam Line Break (MSLB). The recombiners accomplish this by recombining hydrogen and oxygen in a controlled manner to form water vapor. The vapor remains in containment, thus eliminating any discharge to the environment. The hydrogen recombiners are manually initiated since flammability limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent hydrogen recombiners are provided. Each consists of controls and a power supply located in the auxiliary building, and a recombiner located in containment. The recombiners have no moving parts. When a hydrogen recombiner is placed in operation, containment atmosphere is drawn through the unit by natural convection and the temperature of the air is raised to a level sufficient for recombination of the hydrogen and oxygen to occur (approximately 1150°F). A single recombiner is capable of maintaining the hydrogen concentration in containment below the 4.1 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate Engineered Safety Features bus and is provided with a separate power panel and control panel.

BASES

BACKGROUND (continued)

In order for a Hydrogen Recombiner to be considered OPERABLE, at least one containment cooling safety related fan powered from the same electrical train must be in operation or available for operation. Fan operation is necessary to ensure that the post-accident containment atmosphere is adequately mixed preventing local hydrogen buildups in excess of the flammability limit. The supporting fan must be powered from the same electrical train as the recombiner, to assure that it would be available in the event of an accident combined with a Loss of Offsite Power and failure of the opposite Diesel Generator (DG). The fan must be started or verified to be in operation when the recombiners are placed in operation because these fans do not receive an SIS start signal (although they do receive a DBA sequencer start signal). If there is no qualified fan available, the associated recombiner would not have all of its required support equipment and would have to be declared inoperable. Only fans V-1A, V-2A, V-3A, and V-4A (associated with VHX-1, VHX-2, VHX-3, and VHX-4 respectively) are qualified for the post-accident containment environment.

Recombiner M-69B, powered from the Left Train (DG 1-1), is supported by V-4A, which is the only qualified fan powered from the Left Train. If V-4A was unavailable, Hydrogen Recombiner M-69B would have to be declared inoperable.

Recombiner M-69A, powered from the Right Train (DG 1-2), can be supported by V-1A, V-2A, or V-3A, all of which are powered from the Right Train. If V-1A, V-2A, and V-3A were all unavailable, Hydrogen Recombiner M-69A would have to be declared inoperable.

LCO 3.6.6, "Containment Cooling Systems," also contains requirements for containment cooling fan OPERABILITY. The restoration time specified for Containment Air Coolers in LCO 3.6.6 is more restrictive than that specified for Hydrogen Recombiners in LCO 3.6.7.

BASES

APPLICABLE SAFETY ANALYSES

The hydrogen recombiners provide for controlling the bulk hydrogen concentration in containment to less than the lower flammable concentration of 4.1 v/o following a DBA. This control would prevent a containment wide hydrogen burn, thus ensuring the pressure and temperature assumed in the analysis are not exceeded and minimizing damage to safety related equipment located in containment. The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate within containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the primary coolant;

b. Radiolytic decomposition of water in the Primary Coolant System (PCS) and the containment sump;

c. Hydrogen in the PCS at the time of the LOCA (i.e., hydrogen dissolved in the primary coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to Containment Spray System and Emergency Core Cooling Systems solutions.

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions discussed in Reference 3 are used to maximize the amount of hydrogen calculated.

The hydrogen recombiners satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Two hydrogen recombiners must be OPERABLE. In addition, one safety related containment cooling fan associated with each train must be in operation. These requirements ensure OPERABILITY of at least one hydrogen recombiners and adequate mixing of the containment atmosphere in the event of a worst case single active failure.

Operation with at least one hydrogen recombiner ensures that the post LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

BASES

APPLICABILITY

In MODES 1 and 2, two hydrogen recombiners are required to control the post LOCA hydrogen concentration within containment below its flammability limit of 4.1 v/o, assuming a worst case single failure.

In MODES 3 and 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the hydrogen recombiners is low. Therefore, the hydrogen recombiners are not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA are low, due to the pressure and temperature limitations. Therefore, hydrogen recombiners are not required in these MODES.

ACTIONS

A.1

With one containment hydrogen recombiner inoperable, the inoperable recombiner must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE hydrogen recombiner is adequate to perform the hydrogen control function. The 30 day Completion Time is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or MSLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or MSLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

Required Action A.1 has been modified by a Note stating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one hydrogen recombiner is inoperable. This allowance is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or MSLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or MSLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

BASES

ACTIONS (continued)

B.1

If the inoperable hydrogen recombiner 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. 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Performance of a system functional test for each hydrogen recombiner ensures that the recombiners are operational and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR requires verification that the minimum heater sheath temperature increases to ≥ 700°F in ≤ 90 minutes. After reaching 700°F, the power is increased to maximum for approximately 2 minutes and verified to be ≥ 60 kW. The 18 month Frequency is based on past operating history of the recombiners and engineering judgement.

SR 3.6.7.2

This SR ensures that there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failures involve loss of power, blockage of the internal flow path, missile impact, etc. A visual inspection is sufficient to determine abnormal conditions that could cause such failures. The 18 month Frequency for this SR was developed considering that the incidence of hydrogen recombiners failing the SR in the past is low.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.3

This SR requires performance of a resistance to ground test for each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ 10,000 ohms. This SR also requires the performance of a continuity test to ensure there is no single phase fault or any openings of a single heater bank. The continuity test measures the resistance of each phase to neutral. The 18 month Frequency for this SR was developed considering that the incidence of hydrogen recombiners failing the SR in the past is low.

REFERENCES

1. 10 CFR 50.44
2. FSAR, Section 5.1
3. Regulatory Guide 1.7, Revision 1

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 Primary Coolant Pressure Boundary (PCPB) by providing a heat sink for the removal of energy from the Primary Coolant System (PCS) if the preferred heat sink, provided by the condenser and Circulating Water System, is not available.

Twelve MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the FSAR, Section 4.3.4 (Ref. 1). The MSSV rated capacity passes the full steam flow at 102% RTP (100% + 2% for instrument error) with twenty-three valves full open. This meets the requirements of the ASME Boiler and Pressure Vessel Code, Section III (Ref. 2). The MSSV design includes staggered lift settings, according to Table 3.7.1-1, in the accompanying LCO, so that only the number of valves needed will actuate. Staggered lift settings reduce the potential for valve chattering because of insufficient steam pressure to fully open all valves following a turbine reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 1; the purpose is to limit secondary system pressure to ≤ 110% of design pressure when passing 100% of design steam flow. This design basis is sufficient to cope with any Anticipated Operational Occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The events that challenge the MSSV relieving capacity, and thus PCS pressure, are those characterized as decreased heat removal events, and are presented in the FSAR, Sections 14.12 and 14.13 (Refs. 3 and 4) respectfully. Of these, the full power loss of external load event is the most limiting. The event is initiated by either a loss of external electrical load or a turbine trip. No credit is taken for direct reactor trip on turbine trip, the turbine bypass valve, atmospheric dump valves, or pressurizer PORVs. The reduced heat transfer causes an increase in PCS temperature, and the resulting PCS fluid expansion causes an increase in pressure. The PCS pressure increases to ≤ 2614.9 psia, this peak pressure is < 110% of the design pressure, or 2750 psia for the primary system, with the pressurizer safety valves providing relief capacity. The secondary system pressure increases to 1040.8 psia, this pressure is < 110% of the design pressure, or 1100 psia for the secondary system, with the MSSVs providing relief capability.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO requires twenty-three MSSVs to be OPERABLE in compliance with Reference 2. The OPERABILITY of the MSSVs is defined as the ability to open within the lift setting tolerances and to relieve steam generator overpressure. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

The lift settings, according to Table 3.7.1-1 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their designed safety function to mitigate the consequences of accidents that could result in a challenge to the PCPB.

APPLICABILITY

In MODES 1, 2, and 3 a minimum of twenty-three MSSVs are required to be OPERABLE, to provide overpressure protection required by both ASME Code and the accident analysis.

In MODES 4 and 5, there are no credible transients requiring the MSSVs.

BASES

APPLICABILITY (continued)

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.

ACTIONS

A.1

With one or more required MSSVs inoperable, the ability to limit system pressure during accident conditions will be degraded. The four hour Completion Time allows the operator a reasonable amount of time to make minor repairs or adjustments to restore the required number of inoperable MSSVs to OPERABLE status.

B.1 and B.2

If the required MSSVs cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift settings 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 ANSI/ASME OM-1-1987 (Ref. 6). According to Reference 6, the following tests are required for MSSVs:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting); and

d. Compliance with owner's seat tightness criteria.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements.

Table 3.7.1-1 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

The ambient temperature of the operating environment shall be simulated during the set-pressure test in accordance with Reference 6.

REFERENCES

1. FSAR, Section 4.3.4
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components
3. FSAR, Section 14.12
4. FSAR, Section 14.13
5. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWV-1000
6. ANSI/ASME OM-1-1987

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) downstream of the MSIV. MSIV closure terminates flow from the unaffected (intact) steam generator for breaks upstream of the other MSIV.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the Main Steam Safety Valves (MSSVs), atmospheric dump valves, and auxiliary feedwater pump turbine steam supplies to prevent their being isolated from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the other, and isolates the turbine, turbine bypass valve, and other auxiliary steam supplies from the steam generators, assuming the normally closed MSIV bypass valves are closed. The MSIV bypass valves do not receive an isolation signal and might be open during zero power conditions.

The MSIVs close on isolation signals generated by either Steam Generator Low Pressure or Containment High Pressure. The MSIVs fail closed on loss of air. The isolation signal also actuates the Main Feedwater Regulating Valves (MFRVs) and MFRV bypass valves to close. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the Main Steam Line Break (MSLB) inside containment, as discussed in the FSAR, Section 14.18 (Ref. 2). It is also influenced by the accident analysis of the MSLB events presented in the FSAR, Section 14.14 (Ref. 3). The MSIVs are swing disc check valves. The inherent characteristic of this type of valve allows for reverse flow through the valve on a differential pressure even if the valve is closed. In the event of an MSLB, if the MSIV associated with the unaffected steam generator fails to close, both steam generators may blowdown. This failure was not analyzed as part of the original licensing basis of the plant. As such, a Probabilistic Risk Assessment and cost benefit analysis were performed to determine if a facility modification was needed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The results of the analysis as described in an NRC Safety Evaluation dated February 28, 1986 concluded that a double steam generator blowdown event, although more severe than the MSLB used in the original licensing basis of the plant, is not expected to result in unacceptable consequences. Furthermore, the NRC evaluation demonstrated that the potential offsite dose consequences are low and that modifications would not provide a cost beneficial improvement to plant safety.

There are three different limiting MSLB cases that have been evaluated, one for fuel integrity and two for containment analysis (one for containment temperature and one for containment pressure). The limiting case for containment temperature is the hot full power MSLB inside containment following a turbine trip. At hot full power, the stored energy in the primary coolant is maximized.

The limiting case for the containment analysis for containment pressure and fuel integrity is the hot zero power MSLB inside containment. At zero power, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Reverse flow due to the open MSIV bypass valves, contributes to the total release of the additional mass and energy. With the most reactive control rod assumed stuck in the fully withdrawn position, there is an increased possibility that the core will return to power. The core is ultimately shut down by a combination of doppler feedback, steam generator dryout, and borated water injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different MSLB events against different acceptance criteria. The MSLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The MSLB inside containment at hot full 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 a turbine trip.

With offsite power available, the primary coolant pumps continue to circulate coolant through the steam generators, maximizing the Primary Coolant System (PCS) cooldown. With a loss of offsite power, the response of mitigating systems, such as the High Pressure Safety Injection (HPSI) pumps, is delayed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. An MSLB inside containment. For this accident scenario, steam is discharged into containment from both steam generators until closure of the MSIV in the intact steam generator occurs. After MSIV closure, steam is discharged into containment only from the affected steam generator.

b. A break outside of containment and upstream from the MSIVs. This scenario is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled PCS cooldown and positive reactivity addition. Closure of the MSIVs limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs. This type of break will be isolated by the closure of the MSIVs. Events such as increased steam flow through the turbine or the turbine bypass valve will also terminate on closure of the MSIVs.

d. A steam generator tube rupture. For this scenario, closure of the MSIVs isolates the affected steam generator from the intact steam generator and minimizes radiological releases.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO requires that the MSIV in each of the two steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation 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 100.11 (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 both MSIVs are closed and deactivated when there is significant mass and energy in the PCS and steam generators. When the MSIVs are closed, they are already performing their safety function. Deactivation can be accomplished by the removal of the motive force (e.g., air) to the valve to prevent valve opening.

BASES

APPLICABILITY (continued)

In MODE 4, the steam generator energy is low; therefore, the MSIVs are not required to be OPERABLE.

In MODES 5 and 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, time is allowed to restore the component to OPERABLE status. Some repairs can be made to the MSIV with the plant hot. The 8 hour Completion Time is reasonable, considering the probability of an accident occurring during the time period that would require 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.

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in MODE 2 within 6 hours and Condition C would be entered. The Completion Time is reasonable, based on operating experience, to reach MODE 2 in an orderly manner and without challenging plant 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.

The 8 hour Completion Time is consistent with that allowed in Condition A.

BASES

ACTIONS

C.1 and C.2 (continued)

Inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, 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, MSIV status indications available in the control room, and other administrative controls, to ensure these valves are in the closed position.

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status, or closed, within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from MODE 2 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that the closure time of each MSIV is ≤ 5.0 seconds on an actual or simulated actuation signal from each train under no flow conditions. Specific signals (e.g., Containment High Pressure, Steam Generator Low Pressure, handswitch) are tested under Section 3.3, "Instrumentation." The MSIV closure time is assumed in the MSLB and containment analyses. This SR is normally performed upon returning the plant to operation following a refueling outage. The MSIVs are not tested at power since even a part stroke exercise increases the risk of a valve closure with the plant 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 MODES 1 and 2.

The Frequency for this SR is every 18 months. This 18 month Frequency demonstrates the valve closure time at least once per refueling cycle. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

BASES

REFERENCES

1. FSAR, Section 10.2

2. FSAR, Section 14.18

3. FSAR, Section 14.14

4. 10 CFR 100.11

5. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Regulating Valves (MFRVs) and MFRV Bypass Valves

BASES

BACKGROUND

The MFRVs and MFRV bypass valves in conjunction with feed pump speed, control Main Feedwater (MFW) flow to the steam generators for level control during normal plant operation. The valves also isolate MFW flow to the secondary side of the steam generators following a High Energy Line Break (HELB). Closure of the MFRVs and MFRV bypass valves terminates flow to both steam generators. Closure of the MFRV and MFRV bypass valve effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for Main Steam Line Breaks (MSLBs) inside containment, and reducing the cooldown effects.

The MFRVs and MFRV bypass valves isolate MFW in the event of a secondary side pipe rupture inside containment to limit the quantity of high energy fluid that enters containment through the break. Controlled addition of Auxiliary Feedwater (AFW) is provided by a separate piping system.

One MFRV and one MFRV bypass valve are located on each MFW line outside containment. The piping volume from the valves to the steam generator must be accounted for in calculating mass and energy releases following an MSLB.

The MFRVs and MFRV bypass valves close on receipt of an isolation signal generated by either; steam generator low pressure from its respective steam generator, or containment high pressure. These isolation signals also actuate the Main Steam Isolation Valves (MSIVs) to close. The MFRVs and MFRV bypass valves may also be actuated manually. The MFRVs and MFRV Bypass valves are non-safety grade valves located on non-safety grade piping that fail "as-is" on a loss of air. If required, MFW isolation can be accomplished using manually operated valves upstream or downstream of the MFRVs and MFRV Bypass valves. In addition, each MRFV is equipped with a handwheel that can be used to isolate this MFW flowpath.

A description of the MFRVs and MFRV bypass valves is found in the FSAR, Section 10.2.3 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

Closure of the MFRVs is an assumption in the MSLB containment response analysis. Closure of the MFRVs and MFRV bypass valves is also assumed in the MSLB core response (DNB) analysis.

Failure of an MFRV or MFRV bypass valve to close following an MSLB can result in additional mass and energy to the steam generators contributing to cooldown. This failure also results in additional mass and energy releases following an MSLB event. However, this failure was not analyzed as part of the original licensing basis of the plant. As such, a Probabilistic Risk Assessment and cost benefit analysis were performed to determine if a facility modification was needed. The results of the analysis as described in an NRC Safety Evaluation dated February 28, 1986 concluded that a single steam generator blowdown event with continued feedwater, although more severe than the MSLB used in the original licensing basis of the plant, is not expected to result in unacceptable consequences. Furthermore, the NRC evaluation demonstrated that the potential offsite dose consequences are low and that modifications would not provide a cost beneficial improvement to plant safety.

The MFRVs and MFRV bypass valves satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO ensures that the MFRVs and MFRV bypass valves will isolate MFW flow to the steam generators following an MSLB. This LCO requires that both MFRVs and both MFRV bypass valves be OPERABLE. The MFRVs and MFRV bypass valves are considered OPERABLE when the isolation times are within limits, and are closed on an isolation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an MSLB inside containment.

BASES

APPLICABILITY

All MFRVs and MFRV bypass valves must be OPERABLE, or either closed and deactivated, or isolated by closed manually actuated valves, whenever there is significant mass and energy in the Primary Coolant System and steam generators.

In MODES 1, 2, and 3, the MFRVs or MFRV bypass valves are required to be OPERABLE, except when both MFRVs and both MFRV bypass valves are either closed and deactivated, or isolated by closed manually actuated valves, in order to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are either closed and deactivated, or isolated by closed manually actuated valves, they are already performing their safety function.

Once the valves are closed, deactivation can be accomplished by the removal of the motive force (e.g., electrical power, air) to the valve to prevent valve opening. Closing another manual valve in the flow path either remotely (i.e., control room hand switch) or locally by manual operation satisfies isolation requirements.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFRVs and MFRV bypass valves are not required to be OPERABLE.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one MFRV or MFRV bypass valve inoperable, action must be taken to close or isolate the inoperable valve(s) within 8 hours. When these valve(s) are closed or isolated, they are performing their required safety function (e.g., to isolate the line).

The 8 hour Completion Time is reasonable to close the MFRV or MFRV bypass valve, which includes performing a controlled plant shutdown to a condition that supports isolation of the affected valve(s).

BASES

ACTIONS (continued)

B.1 and B.2

If the MFRVs or MFRV bypass valves cannot be restored to OPERABLE status, closed, or isolated in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies the closure time for each MFRV and MFRV bypass valve is ≤ 22.0 seconds on an actual or simulated actuation signal. Specific signals (e.g., steam generator low pressure and containment high pressure) are tested under Section 3.3, "Instrumentation." The MFRV and MFRV bypass valves closure times are bounding values assumed in the MSLB containment response and core response (DNB) analyses (Refs. 3 and 4). This SR is normally performed upon returning the plant to operation following a refueling outage. The MFRVs and MFRV bypass valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the plant generating power. As these valves are not stroke tested at power, they are exempt from the ASME Code, Section XI (Ref. 2) requirements during operation in MODES 1 and 2.

The Frequency is 18 months. The 18 month Frequency for valve closure time is based on the refueling cycle. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency.

REFERENCES

1. FSAR, Section 10.2.3
2. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400
3. FSAR, Section 14.18.2
4. FSAR, Section 14.14

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND

The ADVs provide a method for cooling the plant to Shutdown Cooling (SDC) System entry conditions, should the preferred heat sink via the turbine bypass valve to the condenser not be available, as discussed in the FSAR, Section 10.2 (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 turbine bypass valve.

Four ADVs are provided, two per steam generator. One ADV per steam generator is required following an event rendering one steam generator unavailable for Primary Coolant System (PCS) heat removal.

The ADVs are provided with upstream manual isolation valves to permit their being tested at power, and provide an alternate means of isolation. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate.

The ADVs are provided with a pressurized gas supply from the Bulk Nitrogen System that, on a loss of pressure in the normal instrument air supply, automatically supplies nitrogen to operate the ADVs. The nitrogen backup is not required for ADV OPERABILITY. A description of the nitrogen backup is found in the FSAR, Section 9.5.2 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The design basis of the ADVs is to prevent lifting of the Main Steam Safety Valves (MSSVs) following a turbine and reactor trip, and to provide the capability to cool the plant to SDC System entry conditions when condenser vacuum is lost. A cooldown rate of approximately 75°F per hour is obtainable by one or both steam generators. This design is adequate to cool the plant to SDC System entry conditions with only one ADV and one steam generator, utilizing the cooling water supply available in the Condensate Storage and Supply system.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In certain accident analyses presented in the FSAR, the ADVs are assumed to be used by the operator to cool down the plant to SDC System entry conditions for accidents accompanied by a loss of offsite power. The ADVs are credited for cooldown during a Steam Generator Tube Rupture (SGTR) event. Prior to the operator action, the Main Steam Safety Valves (MSSVs) are used to maintain steam generator pressure and temperature at the MSSV setpoint for 30 minutes following the initiation of an event. The ADVs are also credited in the safety analyses when the Auxiliary Feedwater (AFW) System is required to operate. If AFW pump P-8C is used, operator action may be required to either trip two of four Primary Coolant Pumps (PCPs), start an additional AFW pump, or reduce steam generator pressure. This will allow the required AFW flowrate to the steam generators assumed by the loss of feedwater analysis.

The ADVs are equipped with manual isolation valves in the event an ADV spuriously opens, or fails to close during use.

The ADVs satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

One ADV is required to be OPERABLE on each steam generator to ensure that at least one ADV is OPERABLE to conduct a plant cooldown following an event in which one steam generator becomes unavailable. A closed manual isolation valve does not render its ADV inoperable, since operator action time to open the manual isolation valve is supported in the accident analysis.

Failure to meet the LCO can result in the inability to cool the plant to SDC System entry conditions following an event in which the condenser is unavailable for use with the turbine bypass valve.

An ADV is considered OPERABLE when it is capable of providing a controlled relief of the main steam flow, and is capable of fully opening and closing on demand from either the control room or Hot Shutdown Panel (C-33).

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the ADVs are required to be OPERABLE.

In MODES 5 and 6, there are no credible transients requiring ADVs.

BASES

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.4 does not apply.

With one required ADV inoperable, action must be taken to restore the ADV to OPERABLE status within 7 days. The 7 day Completion Time takes into account the redundant capability afforded by the remaining OPERABLE ADV, and a nonsafety grade backup in the turbine bypass valve and MSSVs.

B.1

With two required ADVs inoperable, action must be taken to restore one of the ADVs to OPERABLE status. As the manual isolation valve can be closed to isolate an ADV, some repairs may be possible with the plant at power. The 24 hour Completion Time is reasonable to repair inoperable ADVs, based on the availability of the turbine bypass valve and MSSVs, and the low probability of an event occurring during this period that requires the ADVs.

C.1 and C.2

If the ADVs cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon the steam generator for heat removal, within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the PCS, the ADVs must be able to be cycled through their full range. This SR ensures the ADVs are tested through a full control cycle at least once per 18 months. Performance of inservice testing or use of an ADV during a plant cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 10.2

2. FSAR, Section 9.5.2

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Primary Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction through a common suction line from the Condensate Storage Tank (CST) (LCO 3.7.6, "Condensate Storage and Supply") and pump to the steam generator secondary side via two separate and independent flow paths to a common AFW supply header for each steam generator. 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 (ADVs) (LCO 3.7.4, "Atmospheric Dump Valves (ADVs)"). If the main condenser is available, steam may be released via the turbine bypass valve.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into two trains. One train (A/B) consists of a motor driven pump (P-8A) and the turbine driven pump (P-8B) in parallel, the discharges join together to form a common discharge. The A/B train common discharge separates to form two flow paths, which feed each steam generator via each steam generator's AFW penetration. The second motor driven pump (P-8C) feeds both steam generators through separate flow paths via each steam generator AFW penetration and forms the other train (C). The two trains join together at each AFW penetration to form a common supply to the steam generators. Each AFW pump is capable of providing 100% of the required capacity to the steam generators as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system.

Each motor driven AFW pump is powered from an independent Class 1E power supply, and feeds both steam generators.

BASES

BACKGROUND (continued)

The steam turbine driven AFW pump receives steam from either main steam header upstream of the Main Steam Isolation Valve (MSIV). Each of the steam feed lines will supply 100% of the requirements of the turbine driven AFW pump. The steam supply from steam generator E-50A receives an open signal from the Auxiliary Feedwater Actuation Signal (AFAS) instrumentation. The steam supply from steam generator E-50B does not. This steam source is a manual backup. The turbine driven AFW pump feeds both steam generators through the same flow paths as motor driven AFW pump P-8A.

One pump at full flow is sufficient to remove decay heat and cool the plant to Shutdown Cooling (SDC) System entry conditions.

The AFW System supplies feedwater to the steam generators during normal plant startup, shutdown, and hot standby conditions.

The AFW System is designed to supply sufficient water to the steam generators to remove decay heat with steam generator pressure at the setpoint of the MSSVs, with exception of AFW pump P-8C. If AFW pump P-8C is used, operator action may be required to either trip two of four Primary Coolant Pumps (PCPs), start an additional AFW pump, or reduce steam generator pressure. This will allow the required flowrates to the steam generators that are assumed in the safety analyses. Subsequently, the AFW System supplies sufficient water to cool the plant to SDC entry conditions, and steam is released through the ADVs, or the turbine bypass valve if the condenser is available.

The AFW System actuates automatically on low steam generator level by an AFAS as described in LCO 3.3.3, "Engineered Safety Feature (ESF) Instrumentation" and 3.3.4, "ESF Logic." The AFAS initiates signals for starting the AFW pumps and repositioning the valves to initiate AFW flow to the steam generators. The actual pump starts are on an "as required" basis. P-8A is started initially, if the pump fails to start, or if the required flow is not established in a specified period of time, P-8C is started. If P-8A and P-8C do not start, or if required flow is not established in a specified period of time, then P-8B is started.

The AFW System is discussed in the FSAR, Section 9.7 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with a loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat, by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest MSSV set pressure plus 3% with the exception of AFW pump P-8C. If AFW pump P-8C is used, operator action may be required to either trip two of the four PCPs, start an additional AFW pump or reduce steam generator pressure. This will allow the required flowrate to the steam generators that are assumed in the safety analyses.

The limiting Design Basis Accident for the AFW System is a loss of normal feedwater.

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident.

The AFW System design is such that it can perform its function following loss of normal feedwater combined with a loss of offsite power with one AFW pump injecting AFW to one steam generator.

The AFW System satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO requires that two AFW trains be OPERABLE to ensure that the AFW System will perform the design safety function to mitigate the consequences of accidents that could result in overpressurization of the primary coolant pressure boundary. Three independent AFW pumps, in two diverse trains, ensure availability of residual heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two pumps from independent emergency buses. The third AFW pump is powered by a diverse means, a steam driven turbine supplied with steam from a source not isolated by the closure of the MSIVs.

BASES

LCO (continued)

The AFW System is considered to be OPERABLE when the components and flow paths required to provide AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to both steam generators. In MODES 1 and 2 the turbine driven AFW pump shall be OPERABLE with redundant steam supplies from each of the two main steam lines upstream of the MSIVs and capable of supplying AFW flow to both steam generators. The piping, valves, instrumentation, and controls in the required flow paths shall also be OPERABLE.

The LCO is modified by three Notes. Note one indicates that only one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4. This is because of reduced heat removal requirements, the short period of time in MODE 4 during which AFW is required, and the insufficient steam pressure available in MODE 4 to power the turbine driven AFW pump. Note two states that the turbine driven AFW pump is only required to be OPERABLE in MODES 1 and 2. This allowance is needed for a sufficient steam pressure to power the turbine driven AFW pump. Note three indicates that any two AFW pumps may be placed in manual mode for the purpose of testing, for not more than 4 hours. In this situation, the third AFW pump would still be available in the event of a plant transient. The two pumps that are in manual could be used at the discretion of the operator.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE and to function in the event that the main feedwater is lost. In addition, the AFW System is required to supply enough makeup water to replace steam generator secondary inventory, lost as the plant cools to MODE 4 conditions.

In MODE 4, the AFW System may be used for heat removal via the steam generator.

In MODES 5 and 6, the steam generators are not normally used for decay heat removal, and the AFW System is not required.

BASES

ACTIONS

A.1

If one of the two steam supplies to the turbine driven AFW pumps is inoperable in MODE 1 or 2, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event requiring the inoperable steam supply to the turbine driven AFW pump.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet the LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completions Times apply simultaneously, and the more restrictive must be met.

B.1

With one or more AFW trains (pump or flow paths) inoperable, for reasons other than Condition A, in MODE 1, 2, or 3, and at least 100% of the required AFW flow available to both steam generators, and at least two AFW pumps OPERABLE, action must be taken to restore the components to OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the AFW System, the time needed for repairs, and the low probability of a DBA event occurring during this period. Two AFW pumps and flow path remain to supply feedwater to both steam generators. The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

BASES

ACTIONS

B.1 (continued)

The 10 day Completion Time provides a limitation time allowed in the specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

When either Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if one or more required AFW components are inoperable with at least 100% of the required AFW flow available to only one steam generator, or only one AFW pump is OPERABLE in MODES 1, 2, and 3, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 30 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

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until at least 100% of the required AFW flow is available to at least one steam generator.

With two trains inoperable and both steam generators having less than 100% of the required AFW flow available in MODES 1, 2, and 3, or the required AFW train inoperable in MODE 4, the plant is in a seriously degraded Condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety grade equipment. In such a condition, the plant 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 at least 100% of the required AFW flow available to at least one steam generator. LCO 3.0.3 is not applicable, as it could force the plant into a less safe condition.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for the required manual, power operated, and automatic valves in the AFW water and steam supply flow paths provides assurance that the proper flow paths exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulations; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

This test need not be performed for the steam driven AFW pump for MODE 3 or 4 operation.

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

SR 3.7.5.2

Verifying that each required AFW pump's developed head at the flow test point is greater than or equal to this required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of pump performance required by Section XI of the ASME Code (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance.

This test need not be performed for the steam driven AFW pump for MODE 3 or 4.

Performance of inservice testing, discussed in the ASME Code, Section XI (Ref. 2), at 3 month intervals satisfies this requirement.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.3

This SR ensures that AFW can be delivered to the appropriate steam generator, in the event of any accident or transient that generates an AFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. Specific signals (e.g., AFAS) are tested under Section 3.3, "Instrumentation." This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is acceptable, based on the design reliability and operating experience of the equipment.

This SR is modified by a Note which states the SR is only required to be met in MODES 1, 2, and 3 when AFW is not in operation. With AFW in operation, the required trains are already aligned with the flow control valves in manual control.

SR 3.7.5.4

This SR ensures that the AFW pumps will start in the event of any accident or transient that generates an AFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. Specific signals (e.g., AFAS, handswitch) are tested under Section 3.3, "Instrumentation."

This test need not be performed for the steam driven AFW pump for MODE 3 or 4 operation.

The 18 month Frequency is acceptable, based on the design reliability and operating experience of the equipment.

This SR is modified by a Note. The Note states that the SR is only required to be met in MODES 1, 2, and 3. In MODE 4, the required pump is already operating and the autostart function is not required.

REFERENCES

1. FSAR, Section 9.7

2. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage and Supply

BASES

BACKGROUND

The Condensate Storage and Supply provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Primary Coolant System (PCS). The Condensate Storage Tank (CST) and the Primary Makeup Storage Tank (T-81) provide a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5, "Auxiliary Feedwater (AFW) System"). Three AFW pumps take a suction from a common line from the CST. T-81 provides makeup to the CST either by use of a pump or by gravity flow. Backup sources from the Service Water System (SWS) and Fire Water System an provide additional water supply to the AFW pump suctions if the normal source is lost. SWS provides an emergency source to AFW pump P-8C, and the Fire Water System provides an emergency source to AFW pumps P-8A and P-8B. The steam produced is released to the atmosphere by the Main Steam Safety Valves (MSSVs) or the atmospheric dump valves. 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 turbine bypass valve. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the CST is a principal component in removing residual heat from the PCS, it is designed to withstand earthquakes. The tornado protected supply is provided by the SWS and Fire Water System. The CST is designed to Seismic Category I requirements to ensure availability of the feedwater supply.

A description of the Condensate Storage and Supply is found in the FSAR, Section 9.7 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The Condensate Storage and Supply provides condensate to remove decay heat and to cool down the plant following all events in the accident analysis, discussed in the FSAR, Chapters 5 and 14. For anticipated operational occurrences and accidents which do not affect the OPERABILITY of the steam generators, the analysis assumption is generally 30 minutes at MODE 3, steaming through the MSSVs followed by a cooldown to Shutdown Cooling (SDC) entry conditions at the design cooldown rate.

The Condensate Storage and Supply satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

To satisfy accident analysis assumptions, the CST and T-81 must contain sufficient cooling water to remove decay heat for 8 hours following a reactor trip from 102% RTP. This amount of time allows for cool down of the PCS to SDC entry conditions, assuming a coincident loss of offsite power and the most adverse single failure. In doing this the CST and T-81 must retain sufficient water to ensure adequate net positive suction head for the AFW pumps, and makeup for steaming required to remove decay heat.

The combined CST and T-81 level required is a usable volume of at least 100,000 gallons, which is based on holding the plant in MODE 3 for 4 hours, followed by a cooldown to SDC entry conditions at approximately 75°F per hour. This basis was established by the Systematic Evaluation Program.

OPERABILITY of the Condensate Storage and Supply System is determined by maintaining the combined tank levels 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 Condensate Storage and Supply is required to be OPERABLE.

In MODES 5 and 6, the Condensate Storage and Supply is not required because the AFW System is not required.

BASES

ACTIONS

A.1 and A.2

If the condensate volume is not within the limit, the OPERABILITY of the backup water supplies must be verified by administrative means within 4 hours and once every 12 hours thereafter.

OPERABILITY of the backup feedwater supplies must include verification of the OPERABILITY of flow paths from the Fire Water System and SWS to the AFW pumps, and availability of the water in the backup supplies. The Condensate Storage and Supply volume must be returned to OPERABLE status within 7 days, as the backup supplies may be performing this function in addition to their normal functions. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the Fire Water System and SWS. Additionally, verifying the backup water supplies every 12 hours is adequate to ensure the backup water supplies continue to be available. The 7 day Completion Time is reasonable, based on OPERABLE backup water supplies being available, and the low probability of an event requiring the use of the water from the CST and T-81 occurring during this period.

B.1 and B.2

If the condensate volume cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on steam generator for heat removal, within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the combination of CST and T-81 contain the required useable volume of cooling water. (This volume ≥ 100,000 gallons.) The 12 hour Frequency is based on operating experience, and the need for operator awareness of plant evolutions that may affect the Condensate Storage and Supply inventory between checks. The 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal CST and T-81 level deviations.

REFERENCES

1. FSAR, Section 9.7

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CCW System also provides this function for various nonessential components, as well as the spent fuel pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System (SWS), and thus to the environment.

The CCW System consists of three pumps connected in parallel to common suction and discharge headers. Any single CCW pump can provide one hundred percent of the required CCW post accident cooling capability. The discharge header splits into two parallel heat exchangers and then combines again into a common distribution header which supplies various heat loads. A common surge tank provides the necessary net positive suction head for the CCW pumps and a surge volume for the system. A train of CCW is considered to be that equipment electrically connected to a common safety bus necessary to transfer heat acquired from the various heat loads to the SWS. There are two CCW trains, each associated with a Safeguards Electrical Distribution Train which are described in Specification 3.8.9, "Distribution Systems - Operating." The CCW train associated with the Left Safeguards Electrical Distribution Train consists of two CCW pumps (P-52A, P-52C), both CCW heat exchangers (E-54A, E-54B), the CCW surge tank (T-3), associated piping, valves, and controls for the equipment to perform their safety function. The CCW train associated with the Right Safeguards Electrical Distribution Train consists of one CCW pump (P-52B), both CCW heat exchangers (E-54A, E-54B), the CCW surge tank (T-3), associated piping, valves, and controls for the equipment to perform their safety function. The pumps and valves are automatically started upon receipt of a safety injection actuation signal and all essential valves are aligned to their post accident positions. CCW valve repositioning also occurs following a Recirculation Actuation Signal (RAS) which aligns associated valves to provide full cooling to the CCW heat exchangers during the recirculation phase following a design basis Loss of Coolant Accident (LOCA).

BASES

BACKGROUND (continued)

The Component Cooling System cools three groups of loads. The CCW loads are described in the FSAR (Ref. 1), the major loads are:

1. Safety related loads outside the containment,
   Shutdown Cooling Heat Exchangers
   Engineered Safeguards Pump Coolers
   Charging Pump Oil Coolers

2. Non-safety related loads outside the Containment, and
   Spent Fuel Cooling Heat Exchangers
   Waste Gas Compressors
   Rad Waste Evaporators

3. Non-safety related loads inside the Containment.
   Letdown Heat Exchanger
   Shield Cooling Heat Exchangers
   Primary Coolant Pump Leakoff and Oil Coolers
   CRDM Seal Coolers

Each of these groups of loads can be cooled by the flow from one CCW pump. During normal operation, when full flow is not being provided to the Shutdown Cooling and Letdown Heat Exchangers, two CCW pumps can provide the required flow for all three groups of loads.

During post accident conditions, with all CCW and related system components OPERABLE, one hundred percent of the required CCW post accident cooling capability can be provided by any one CCW pump with sufficient flow margin to allow manually restoring CCW flow to the Spent Fuel Pool Cooling Heat Exchangers. If CCW or related systems have components out of service, additional CCW pumps may be required to provide the required cooling capability.

For post accident cooling, the Engineered Safety Features signals reposition several valves to maximize containment cooling and conserve CCW flow. Initially, a safety injection signal will start the CCW pumps, and open the large CCW inlet valves to the Shutdown Cooling Heat Exchangers (CCW cools the Shutdown Cooling Heat Exchangers, which cool the containment spray flow). A safety injection signal will also isolate the non-safety related CCW loads outside the containment. A Containment High Pressure signal will isolate the non-safety related CCW loads inside the containment. The occurance of these automatic actions will provide the required CCW post accident cooling capability while limiting the CCW flow requirement to that which can be provided by one CCW pump.

BASES

BACKGROUND (continued)

One hundred percent of the required CCW post accident cooling capability can be provided by one CCW pump if CCW flow to both non-safety related flow paths can be isolated. (Since one pump can supply the safety-related loads and the Spent Fuel Pool Cooling Heat Exchangers, isolation capability for that heat exchanger is not necessary.) The necessary isolation of each non-safety related CCW flow path may be accomplished by any one of three valves.

1. The capability to isolate CCW flow to the non-safety related loads in the containment requires one CCW Containment Isolation Valve, CV-0910, CV-0911, or CV-0940, to be OPERABLE.

2. The capability to isolate CCW flow to the non-safety related loads outside the containment requires one CCW header isolation valve in the non-safety related CCW header outside the containment, CV-0944, CV-0944A, or CV-0977B, to be OPERABLE.

One hundred percent of the required CCW post accident cooling capability can be provided by two CCW pumps if CCW flow to either non-safety related flow path can be isolated.

One hundred percent of the required CCW post accident cooling capability can be provided by three CCW pumps even with CCW flow being provided to both the safety-related loads, and the non-safety related loads inside and outside the containment.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Section 9.3 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Shutdown Cooling (SDC) System heat exchangers. This may utilize the SDC heat exchangers, during a normal or post accident cooldown and shutdown in conjunction with the Containment Spray System during the recirculation phase following a LOCA.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is for one CCW train in conjunction with the SWS and a 100% capacity Containment Cooling System (containment spray, containment coolers, or a combination) removing core decay heat between 20 to 40 minutes after a design basis LOCA. This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA, and provides a gradual reduction in the temperature of this fluid as it is supplied to the Primary Coolant System (PCS) by the safety injection pumps. Any single CCW pump can provide one hundred percent of the required CCW post accident cooling capability.

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power. The CCW System also functions to cool the plant from SDC entry conditions (T_{ave} < 300°F) to MODE 5 (T_{ave} < 200°F) during normal and post accident operations. The time required to cool from 300°F to 200°F is a function of the number of CCW and SDC trains operating. This assumes that the maximum Lake Michigan water temperature of LCO 3.7.9, "Ultimate Heat Sink (UHS)," occurs simultaneously with the maximum heat loads on the system.

The CCW System satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The CCW trains are independent of each other to the degree that each has separate controls and power supplies. In the event of a DBA, one CCW train 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 CCW trains must be OPERABLE. At least one CCW train will operate assuming the worst single active failure occurs coincident with the loss of offsite power.

The CCW train associated with the Left Safeguards Electrical Distribution Train is considered OPERABLE when:

a. CCW pumps P-52A and P-52C are OPERABLE;

b. Surge tank T-3 is OPERABLE;

c. Both CCW heat exchangers E-54A and E-54B are OPERABLE; and

BASES

LCO (continued)

d. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

The CCW train associated with the Right Safeguards Electrical Distribution Train is considered OPERABLE when:

a. CCW pump P-52B is OPERABLE;

b. Surge tank T-3 is OPERABLE;

c. Both CCW heat exchangers E-54A and E-54B are OPERABLE; and

d. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

The isolation of CCW from other components or systems not required for safety may render those components or systems inoperable, but does not affect the OPERABILITY of the CCW System.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system that must be prepared to perform its post accident safety functions, primarily PCS heat removal by cooling the SDC heat exchanger.

In MODES 5 and 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

With one or more trains of CCW inoperable, but at least 100% of the required CCW post accident cooling capability available, the inoperable components must be restored to OPERABLE status within 72 hours.

Any single CCW pump can provide one hundred percent of the required CCW post accident cooling capability. This condition allows for the loss of any two CCW pumps even if they are supplied from different electrical trains of power as long as one CCW pump is available. It also would allow for the inoperability of one or more of those valves, closed by Safety Injection, which isolate cooling to non-essential loads, provided there are sufficient CCW pumps available to supply the additional flow.

BASES

ACTION

A.1 (continued)

The Component Cooling System cools three groups of loads:

1. Safety related loads outside the containment,

2. Non-safety related loads outside the Containment, and

3. Non-safety related loads inside the Containment.

As discussed in the Background section of these bases, each of these groups of loads can be cooled by the flow from one CCW pump.

One hundred percent of the required CCW post accident cooling capability can be provided by one CCW pump if:

1. One CCW Containment Isolation Valve, CV-0910, CV-0911, or CV-0940, is OPERABLE, and

2. One CCW header isolation valve for the non-safety related loads outside the containment, CV-0944, CV-0944A, or CV-0977B, is OPERABLE.

One hundred percent of the required CCW post accident cooling capability can be provided by two CCW pumps if:

1. One CCW Containment Isolation Valve, CV-0910, CV-0911, or CV-0940, is OPERABLE, or

2. One CCW header isolation valve for the non-safety related loads outside the containment, CV-0944, CV-0944A, or CV-0977B, is OPERABLE.

One hundred percent of the required CCW post accident cooling capability can be provided by three CCW pumps even with CCW flow being provided to both the safety-related loads, and the non-safety related loads inside and outside the containment.

The 72 hour Completion Time was developed taking into account the redundant heat removal capability afforded by the remaining CCW components and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

B.1 and B.2

If the required CCW trains cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in 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 3.7.7.1

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. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in their correct position.

This SR is modified by a Note indicating that the isolation of the CCW to components or systems may render those components inoperable but does not affect the OPERABILITY of the CCW System.

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.2

This SR verifies proper automatic operation of the CCW valves on an actual or simulated actuation signal. Specific signals (e.g., safety injection, RAS) are tested under Section 3.3, "Instrumentation." This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. This SR is modified by a Note which states this SR is only required to be met in MODES 1, 2, and 3. The instrumentation providing the input signal is not required in MODE 4, therefore, to keep consistency with Section 3.3, "Instrumentation," the SR is not required to be met in this MODE. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.3

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal in the "with standby power available" mode which tests the starting of the pumps by the SIS-X relays. The starting of the pumps by the sequencer is performed in Section 3.8, "Electrical Power Systems." This SR is modified by a Note which states this SR is only required to be met in MODES 1, 2, and 3. The instrumentation providing the input signal is not required in MODE 4, therefore, to keep consistency with Section 3.3, "Instrumentation," the SR is not required to be met in this MODE. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 9.3

B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water System (SWS)

BASES

BACKGROUND

The SWS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation or a normal shutdown, the SWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SWS consists of three pumps connected in parallel taking suction from a common intake structure supplied by Lake Michigan. The discharge of the pumps flow into a common header before splitting into three headers (two critical headers for safety-related equipment and a single non-critical header for non safety-related equipment). The return piping from the three headers join into a common line and discharge to the cooling tower makeup basin. A train of SWS shall be that equipment electrically connected to a common safety bus necessary to remove heat from the various heat loads. There are two SWS trains, each associated with a Safeguards Electrical Train which are described in Specification 3.8.9, "Distribution Systems - Operating." The SWS train associated with the Left Safeguards Train consists of one SWS pump (P-7B), associated piping, valves, and controls for the equipment to perform their safety function. The SWS train associated with the Right Safeguards Train consists of two SWS pumps (P-7A, P-7C), associated piping, valves, and controls for the equipment to perform their safety function. The pumps and valves are remote manually aligned, except in the unlikely event of a Loss Of Coolant Accident (LOCA). The pumps are automatically started by a safety injection actuation signal and all essential valves are aligned to their post accident positions. SWS valve repositioning also occurs following receipt of a Recirculation Actuation Signal (RAS) which aligns associated valves to provide full cooling to the component cooling water heat exchangers during the recirculation phase following a design basis LOCA.

The DG which powers two SWS pumps (P-7A, P-7C), also powers the fans associated with VHX-1, VHX-2, and VHX-3 (V-1A, V-2A and V-3). This is necessary because if reliance for containment cooling is placed solely on one spray pump and three CACs, at least two service water pumps must be OPERABLE to provide the necessary service water flow to assure OPERABILITY of the CACs.

BASES

BACKGROUND (continued)

The Service Water System cools three groups of loads. The SWS loads are described in the FSAR (Ref. 1), the major loads are:

1. Critical loads inside the Containment,
   Containment Air Coolers VHX-1, VHX-2, VHX-3, (and VHX-4).

2. Critical loads outside the Containment, and
   Diesel Generators 1-1 and 1-2
   Component Cooling Heat Exchangers E-54A and E-54B
   Engineered Safeguards Room Coolers VHX-27A and VHX-27B
   Control Room HVAC Coolers VC-10 and VC 11
   Instrument Air Compressors C-2A and C-2C

3. Non-critical loads in the Turbine Building

Each of these groups of loads can be cooled by the flow from one SWS pump. During normal operation, when SWS flow from the containment air coolers and CCW heat exchangers is throttled by temperature control valves, two SWS pumps can provide the required flow for all three groups of loads.

During post accident conditions, with all SWS and related system components OPERABLE, one hundred percent of the required SWS post accident cooling capability can be provided by any one SWS pump. If SWS or related systems have components out of service, additional SWS pumps may be required to provide the required cooling capability.

For post accident cooling, the Engineered Safety Features signals reposition several valves to maximize containment cooling and conserve SWS flow. Initially, a safety injection signal will start the SWS pumps, open the large SWS outlet valves from the CACs (which cool the containment atmosphere), and close the non-critical SWS header isolation valve. Subsequently, if the Safety Injection Refueling water tank has been emptied, a recirculation actuation signal will open the large SWS outlet valves on the CCW heat exchangers (CCW cools the Shutdown Cooling Heat Exchangers, which cool the containment spray flow). The occurance of these automatic actions will provide the required post accident SWS cooling requirement while limiting the SWS flow requirement to that which can be provided by two SWS pumps.

BASES

BACKGROUND (continued)

If two Containment Spray Pumps are available, the Containment Air Coolers are not needed for post accident containment cooling. SWS flow to the containment may then be isolated, further reducing the SWS post accident cooling requirement to that which can be provided by one SWS pump.

One hundred percent of the required SWS post accident cooling capability can be provided by any one SWS pump if SWS flow both to the non-critical header and to the critical loads inside the containment are capable of being isolated.

1. The capability to isolate SWS flow to the non-critical SWS header requires its isolation valve, CV-1359, to be OPERABLE.

2. The allowance to isolate SWS flow to the containment requires two Containment Spray pumps to be OPERABLE to provide containment heat removal.

   The capability to isolate SWS flow to the containment requires one SWS Containment Isolation Valve, CV-0824 or CV-0847, to be OPERABLE.

One hundred percent of the required SWS post accident cooling capability can be provided by any two SWS pumps if SWS flow either to the non-critical header or to the critical loads inside the containment are capable of being isolated.

One hundred percent of the required SWS post accident cooling capability can be provided by three SWS pumps even with SWS flow being provided to both the CACs and the Non-critical SWS header.

Additional information about the design and operation of the SWS, along with a list of the components served, is presented in the FSAR, Section 9.1 (Ref. 1). The principal safety related function of the SWS is the removal of decay heat from the reactor via the Component Cooling Water (CCW) System.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the SWS is for one SWS train, in conjunction with the CCW System and a 100% capacity containment cooling system (containment spray, containment coolers, or a combination), removing core decay heat between 20 to 40 minutes following a design basis LOCA. This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Primary Coolant System by the safety injection pumps. The SWS is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The SWS, in conjunction with the CCW System, also cools the plant from Shutdown Cooling (SDC) entry Condition, as discussed in the FSAR, Section 6.1 (Ref. 2) to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CCW and SDC System trains that are operating. This assumes that the maximum Lake Michigan water temperature of LCO 3.7.9, "Ultimate Heat Sink (UHS)," occurs simultaneously with maximum heat loads on the system.

The SWS satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

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

The SWS train associated with the Left Safeguard Electrical Distribution Train is considered OPERABLE when:

a. SWS pump P-7B is OPERABLE; and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

The SWS train associated with the Right Safeguards Electrical Distribution Train is OPERABLE when:

a. SWS pumps P-7A and P-7C are OPERABLE; and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

BASES

LCO (continued)

The isolation of SWS from other components or systems not required for safety may render those components or systems inoperable but does not affect the OPERABILITY of the SWS System.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS System is a normally operating system, which is required to support the OPERABILITY of the equipment serviced by the SWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

ACTIONS

A.1

With one or more trains of SWS inoperable, but at least 100% of the required SWS post accident cooling capability available, the inoperable components must be restored to OPERABLE status within 72 hours.

This condition allows for the loss of any two SWS pumps even if they are supplied from different electrical trains of power. If two SWS pumps are inoperable, then at least two containment spray pumps must be OPERABLE to provide the required post accident containment cooling without reliance on the CACs (which require more service water flow than can be provided by a single pump). This condition would also allow for the inoperability of one or more of those valves, closed by a Safety Injection Signal, which isolate cooling to non-essential loads, provided there are sufficient SWS pumps available to supply the additional flow.

The Service Water System cools three groups of loads:

1. Critical loads inside the Containment,

2. Critical loads outside the Containment, and

3. Non-critical loads in the Turbine Building.

As discussed in the Background section of these bases, each of these groups of loads can be cooled by the flow from one SWS pump.

BASES

ACTIONS

A.1 (continued)

One hundred percent of the required SWS post accident cooling capability can be provided by any one SWS pump if:

1. The non-critical SWS header isolation valve, CV-1359, is OPERABLE, and

2. Two Containment Spray pumps and one SWS Containment Isolation Valve, CV-0824 or CV-0847, are OPERABLE.

One hundred percent of the required SWS post accident cooling capability can be provided by any two SWS pumps if:

1. The non-critical SWS header isolation valve, CV-1359, is OPERABLE, or

2. Two Containment Spray pumps and one SWS Containment Isolation Valve, CV-0824 or CV-0847, are OPERABLE.

One hundred percent of the required SWS post accident cooling capability can be provided by three SWS pumps even with SWS flow being provided to both the CACs and the Non-critical SWS header.

The 72 hour Completion Time was developed taking into account the redundant heat removal capability afforded by the remaining SWS components and the low probability of a DBA occurring during this period.

B.1 and B.2

If the required SWS trains cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

Verifying the correct alignment for manual, power operated, and automatic valves in the SWS flow path ensures that the proper flow paths exist for SWS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR is modified by a Note indicating that the isolation of SWS to components or systems may render those components inoperable but does not affect the OPERABILITY of the SWS.

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

SR 3.7.8.2

This SR verifies proper automatic operation of the SWS valves on an actual or simulated actuation signal. Specific signals (e.g., safety injection) are tested under Section 3.3, "Instrumentation." This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. This SR is modified by a Note which states this SR is only required to be met in MODES 1, 2, and 3. The instrumentation providing the input signal is not required in MODE 4, therefore, to keep consistency with Section 3.3, "Instrumentation," the SR is not required to be met in this MODE. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.3

The SR verifies proper automatic operation of the SWS pumps on an actual or simulated actuation signal in the "with standby power available" mode which tests the starting of the pumps by the SIS-X relays. The starting of the pumps by the sequencer is performed in Section 3.8, "Electrical Power Systems." This SR is modified by a Note which states this SR is not required to be met in MODE 4. The instrumentation providing the input signal is not required in MODE 4, therefore, to keep consistency with Section 3.3, "Instrumentation," the SR is not required to be met in this MODE. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 9.1

2. FSAR, Section 6.1

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for process and operating heat from safety related components during a Design Basis Accident (DBA) or transient, as well as during normal operation. This is done utilizing the Service Water System (SWS).

The UHS has been defined as Lake Michigan. The two principal functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

The basic performance requirements are that an adequate Net Positive Suction Head (NPSH) to the SWS pumps be available, and that the design basis temperatures of safety related equipment not be exceeded.

Additional information on the design and operation of the system along with a list of components served can be found in FSAR, Section 9.1 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the plant is cooled down and placed on shutdown cooling. Maximum post accident heat load occurs between 20 to 40 minutes after a design basis Loss of Coolant Accident (LOCA). Near this time, the plant switches from injection to recirculation, and the containment cooling systems are required to remove the core decay heat.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The minimum water level of the UHS is based on the NPSH requirements for the SWS pumps. The NPSH calculation assumes a minimum water level of 4 feet above the bottom of the pump suction bell which corresponds to an elevation of 557.25 ft. Violation of the SWS pump submergence requirement should never become a factor unless the Lake Michigan water level falls below the top of the sluice gate opening which is at elevation 568.25 ft. Early warning of a falling intake water level is provided by the intake structure level alarm. The nominal lake level is approximately 580 ft mean sea level. The minimum water temperature of the UHS is based on conservative heat transfer analyses for the worst case LOCA. FSAR, Section 14.18 (Ref. 2) and Design Basis Document (DBD) 1.02 (Ref. 3) provide the details of the analysis which forms the basis for these operating limits. The assumptions include: worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and the worst case single active failure.

The UHS satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The UHS is required to be OPERABLE. The UHS is considered OPERABLE if it contains a sufficient volume of water at or below the maximum temperature that would allow the SWS to operate without the loss of NPSH, and without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the UHS temperature should not exceed 81.5°F and the level should not fall below 568.25 ft above mean sea level during normal plant operation.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

BASES

ACTIONS

A.1 and A.2

If the UHS is inoperable, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in 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 3.7.9.1

This SR verifies adequate cooling can be maintained. The level specified also ensures sufficient NPSH is available for operating the SWS pumps. The 24 hour Frequency is based on operating experience related to the trending of the parameter variations during the applicable MODES. This SR verifies that the UHS water level is ≥ 568.25 ft above mean sea level as measured within the boundaries of the intake structure.

SR 3.7.9.2

This SR verifies that the SWS is available to provide adequate cooling for the maximum accident or normal design heat loads following a DBA. The 24 hour Frequency is based on operating experience related to the trending of the parameter variations during the applicable MODES. This SR verifies that the water temperature from the UHS is ≤ 81.5°F.

REFERENCES

1. FSAR, Section 9.1

2. FSAR, Section 14.18

3. Design Basis Document (DBD) 1.02, "Service Water System"

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Ventilation (CRV) Filtration

BASES

BACKGROUND

The CRV Filtration provides a protected environment from which operators can control the plant following an uncontrolled release of radioactivity.

The CRV Filtration consists of a common emergency intake which splits into two independent, redundant trains that recirculate and filter the control room air. The exhaust of each train exhausts into a common supply plenum. Each train consists of a prefilter, a heater, a High Efficiency Particulate Air (HEPA) filter, two banks of activated charcoal adsorbers for removal of gaseous activity (principally iodine), a second HEPA filter, and a fan. Ductwork, valves or dampers, and instrumentation also form part of the system. A second bank of HEPA filters follows the adsorber section to collect carbon fines, and to back up the main HEPA filter bank if it fails.

The CRV Filtration is an emergency system, part of which may also operate during normal plant operations in the standby mode of operation. Upon manual initiation or receipt of a containment high pressure or containment high radiation signal, normal air supply to the control room is isolated, and the stream of ventilation air is recirculated through the filter trains of the system. The prefilters remove any large particles in the air. Continuous operation of each train for at least 10 hours per month with the heaters on reduces moisture buildup on the HEPA filters and adsorbers. The heater is important to the effectiveness of the charcoal adsorbers.

Actuation of the system to the emergency mode of operation closes the normal unfiltered outside air intake and unfiltered exhaust dampers, opens the emergency air intake, and aligns the system for recirculation of control room air through the redundant trains of HEPA and charcoal filters. The emergency mode initiates pressurization and filtered ventilation of the air supply to the control room.

Outside air is filtered, and then added to the air being recirculated from the control room. Pressurization of the control room prevents infiltration of unfiltered air from the surrounding areas of the building.

BASES

BACKGROUND (continued)

A single train will pressurize the control room to at least 0.125 inches water gauge relative to the south hallway outside the Control Room Viewing Galley, and provides an air exchange rate in excess of 25% per hour. The CRV Filtration operation in maintaining the control room habitable is discussed in the FSAR, Section 9.8 (Ref. 1).

Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across one 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 CRV Filtration is designed in accordance with Seismic Category I requirements.

The CRV Filtration is designed to maintain the control room environment for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem whole body dose or its equivalent to any part of the body.

APPLICABLE SAFETY ANALYSES

The CRV Filtration components are arranged in redundant safety related ventilation trains. The location of components and ducting within the control room envelope ensures an adequate supply of filtered air to all areas requiring access.

The CRV Filtration provides airborne radiological protection for the control room operators, as demonstrated by the control room accident dose analyses for the most limiting design basis events discussed in the FSAR, Chapter 14 (Ref. 2).

The worst case single active failure of a component of the CRV Filtration, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The CRV Filtration satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Two independent and redundant trains of the CRV Filtration are required to be OPERABLE to ensure that at least one is available, assuming that a single failure disables the other train. Total system failure could result in a control room operator receiving a dose in excess of 5 rem in the event of a large radioactive release.

BASES

LCO (continued)

The CRV Filtration is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE in both trains. A CRV Filtration train is considered OPERABLE when the associated:

a. Main recirculation fan and emergency filter fan are OPERABLE;

b. HEPA filters and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Required heater, ductwork, valves, and dampers are OPERABLE,

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors such that 0.125 inches water gauge positive pressure can be maintained.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CRV Filtration must be OPERABLE to limit operator exposure during and following a DBA.

In MODES 5 and 6, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining CRV Filtration OPERABLE is not required in MODE 5 or 6, except for the following situations under which significant radioactive releases can be postulated:

a. During CORE ALTERATIONS;

b. During movement of irradiated fuel assemblies; and

c. During movement of a fuel cask in or over the SFP.

BASES

ACTIONS

A.1

With one CRV Filtration train inoperable, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRV Filtration subsystem is adequate to perform control room radiation protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CRV Filtration train could result in loss of CRV Filtration function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and the ability of the remaining train to provide the required capability.

B.1 and B.2

If the inoperable CRV Filtration train cannot be restored to OPERABLE status within the required Completion Time of Condition A in MODE 1, 2, 3, or 4, the plant must be placed in a MODE that minimizes the accident risk. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2.1, C.2.2, and C.2.3

During CORE ALTERATIONS, during movement of irradiated fuel assemblies, during movement of a fuel cask in or over the SFP, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE CRV Filtration train must be immediately placed in the emergency mode of operation. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel assemblies or a fuel cask to a safe position.

BASES

ACTIONS (continued)

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

During CORE ALTERATIONS, during movement of irradiated fuel assemblies, or during movement of a fuel cask in or over the SFP, with two CRV Filtration trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might enter the control room. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel assemblies or a fuel cask to a safe position.

E.1

If both CRV Filtration trains are inoperable in MODE 1, 2, 3, or 4, the CRV Filtration may not be capable of performing the intended function and the plant is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. Since the environment and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check on this system.

Monthly heater operations dry out any moisture accumulated in the charcoal from humidity in the ambient air. Each train must be operated for ≥ 10 continuous hours with the associated heater, VHX-26A or VHX-26B, energized. The 31 day Frequency is based on the known reliability of the equipment, and the two train redundancy available.

SR 3.7.10.2

This SR verifies that the required CRV Filtration testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CRV Filtration filter tests are in accordance with Regulatory Guide 1.52 (Ref. 3) as described in the VFTP. The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.3

This SR verifies each CRV Filtration train starts and operates on an actual or simulated actuation signal. Specific signals (e.g., containment high pressure, containment high radiation) are tested under Section 3.3, "Instrumentation." This SR is modified by a Note which states this SR is only required to be met in MODES 1, 2, 3 and 4 and during movement of irradiate fuel assemblies in containment. The instrumentation providing the input signal is not required in these plant conditions, therefore, to keep consistency with Section 3.3, "Instrumentation," the SR is not required to be met. The Frequency of 18 months is consistent with that specified in Reference 3.

SR 3.7.10.4

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the CRV Filtration. During the emergency mode of operation, the CRV Filtration is designed to pressurize the control room ≥ 0.125 inches water gauge positive pressure with respect to adjacent areas in order to prevent unfiltered inleakage. The CRV Filtration is designed to maintain this positive pressure with one train at an emergency ventilation flow rate of ≥ 3040 cfm and ≤ 3520 cfm. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.4 (Ref. 4).

REFERENCES

1. FSAR, Section 9.8
2. FSAR, Chapter 14
3. Regulatory Guide 1.52 (Rev. 2)
4. NUREG-0800, Section 6.4, Rev. 2, July 1981

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Ventilation (CRV) Cooling System

BASES

BACKGROUND

The CRV Cooling provides temperature control for the control room during normal and emergency conditions.

The CRV Cooling consists of two independent, redundant trains, which exhaust into a common supply plenum that provide cooling and heating of recirculated control room air. In the emergency mode, the two trains are supplied by a common emergency intake which splits into the two trains. Each train consists of heating coils, cooling coils, instrumentation, and controls to provide for control room temperature control. The CRV Cooling is a subsystem providing air temperature control for the control room.

The CRV Cooling is an emergency system, parts of which may also operate during normal plant operations. A single train will provide the required temperature control to maintain the control room at 90°F or below. The CRV Cooling operation to maintain the control room temperature is discussed in the FSAR, Section 9.8 (Ref. 1).

The control room ventilation emergency mode of operation is actuated either by a containment high radiation signal or a containment high pressure signal, or manually from the control room. During emergency mode operation, the air handling units and the charcoal filter units of both Train A and Train B are actuated automatically. The CRV Cooling refrigerant Condensing Units VC-10 and VC-11 shut down and are manually restarted by the operator when their operation is required for control room cooling. In addition, since immediate operation of the CRV Cooling System is not necessary, other manual operations may be required to initiate control room cooling, depending on the configuration of the system upon initiation of the emergency mode signal.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the CRV Cooling is to maintain temperature of the control room environment throughout 30 days of continuous occupancy.

The CRV Cooling components are arranged in redundant safety related trains. During normal and emergency operation, the CRV Cooling maintains the temperature at 90°F or below, as required by LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." A single active failure of a component of the CRV Cooling, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The CRV Cooling is designed in accordance with Seismic Category I requirements. The CRV Cooling is capable of removing sensible and latent heat loads from the control room, considering equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

The CRV Cooling satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Two independent and redundant trains of the CRV Cooling are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident. In addition, since immediate operation of the CRV Cooling System is not necessary, other manual operations may be required to initiate control room cooling, depending on the configuration of the system upon initiation of the emergency mode signal.

The CRV Cooling is considered OPERABLE when the individual components that are necessary to maintain the control room temperature are OPERABLE in both trains. These components include the condensing units, fans, and associated temperature control instrumentation. In addition, the CRV Cooling must be OPERABLE to the extent that air circulation can be maintained.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the CRV Cooling must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY requirements following isolation of the control room.

In MODES 5 and 6, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining CRV Cooling OPERABLE is not required in MODE 5 or 6, except for the following situations under which significant radioactive releases can be postulated:

a. During CORE ALTERATIONS;

b. During movement of irradiated fuel assemblies; and

c. During movement of a fuel cask in or over the SFP.

ACTIONS

A.1

With one CRV Cooling train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CRV Cooling train is adequate to maintain the control room temperature within limits. The 30 day Completion Time is reasonable, based on the low probability of an event occurring requiring control room isolation, consideration that the remaining train can provide the required capabilities.

B.1 and B.2

In MODE 1, 2, 3, or 4, when Required Action A.1 cannot be completed within the required Completion Time, the plant must be placed in a MODE that minimizes the accident risk. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1, C.2.1, C.2.2, and C.2.3

During CORE ALTERATIONS, during movement of irradiated fuel assemblies, or during movement of a fuel cask in or over the SFP, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE CRV Cooling train must be placed in operation immediately. This action ensures that the remaining train is OPERABLE, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel assemblies or a fuel cask to a safe position.

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

During CORE ALTERATIONS, during movement of irradiated fuel assemblies, or during movement of a fuel cask in or over the SFP, with two CRV Cooling trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the plant in a Condition that minimizes the accident risk. This does not preclude the movement of fuel assemblies or a fuel cask to a safe position.

E.1

If both CRV Cooling trains are inoperable in MODE 1, 2, 3, or 4, the CRV Cooling may not be capable of performing the intended function and the plant is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies that the heat removal capability of the system is sufficient to meet design requirements. This SR consists of a combination of testing and calculations. An 18 month Frequency is appropriate, since significant degradation of the CRV Cooling is slow and is not expected over this time period.

REFERENCES

1. FSAR, Section 9.8

B 3.7 PLANT SYSTEMS

B 3.7.12 Fuel Handling Area Ventilation System

BASES

BACKGROUND

The Fuel Handling Area Ventilation System filters airborne radioactive particulates from the area of the spent fuel pool following a fuel handling accident or a fuel cask drop accident. The fuel handling area is served by two separate subsystems one being part of the original plant design, and the other being added as part of the Auxiliary Building Addition.

The original plant design consists of a supply plenum and an exhaust plenum including associated ductwork, dampers, and instrumentation. The supply plenum contains one prefilter, two heating coils, and one supply fan. The exhaust plenum contains two filter banks (normal and emergency) configured in a parallel flow arrangement, and two independent exhaust fans which draw air from a common duct. The "normal filter bank" contains a prefilter and a High Efficiency Particulate Air (HEPA) filter. The "emergency filter bank" contains a prefilter, HEPA filter, and an activated charcoal filter.

The Auxiliary Building Addition, which was added to serve the spaces at the north end of the spent fuel pool, also consist of a supply plenum and exhaust plenum. The supply plenum is configured similar to the supply plenum provided in the original plant design and includes one prefilter, two heating coils, and one supply fan. The exhaust plenum is different from the original plant design in that it only contains one filter bank consisting of a prefilter and HEPA filter, and two common exhaust fans.

During normal plant operations, the Fuel Handling Area Ventilation System supplies filtered and heated (as needed) outside air to the fuel handling area. The exhaust fans draw air from the fuel handling area through the normally aligned prefilters and HEPA filters and discharge it to the unit stack by way of the main ventilation exhaust plenum.

BASES

BACKGROUND (continued)

During plant evolutions when the possibility for a fuel handling accident or fuel cask drop accident exist, the Fuel Handling Area Ventilation System is configured such that all fans are stopped except one exhaust fan in the original plant subsystem aligned to the "emergency filter bank." The "normal filter bank" in the original plant design is isolated by closing its associated inlet damper. Thus, in the event of a fuel handling accident, the fuel handling area atmosphere will be filtered for the removal of airborne fission products prior to being discharged to the outside environment.

The Fuel Handling Area Ventilation System is discussed in the FSAR, Sections 9.8, 14.11 and 14.19 (Refs. 1, 2, and 3) because it may be used for normal, as well as post-accident, atmospheric cleanup functions.

APPLICABLE SAFETY ANALYSES

The Fuel Handling Area Ventilation System is designed to mitigate the consequences of a fuel handling accident or fuel cask drop accident by limiting the amount of airborne radioactive material discharged to the outside atmosphere.

The results and major assumptions used in the analysis of the fuel handling accident are presented in FSAR Section 14.19. For the purpose of defining the upper limit of the radiological consequences of a fuel handling accident, it is assumed that a fuel bundle is dropped during fuel handling activities and all the fuel rods in the equivalent of an entire assembly (216) fail. The bounding fuel handling accident is assumed to occur in containment two days after shutdown. No containment isolation is assumed to occur. As such, the released fission products escape to the environment with no credit for filtration. The results of this analysis have shown that the offsite doses resulting from this event are within the guideline of 10 CFR 100. In the event a fuel handling accident were to occur in the fuel handling area, the radioactive release would pass through the "emergency filter bank" significantly reducing the amount of radioactive material released to the environment. Thus, the consequences of a fuel handling accident in the fuel handling area are deemed acceptable with or without the "emergency filter bank" in operation since they are no more severe than the consequences of a fuel handling accident in containment.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The results and major assumptions used in the analysis of the fuel cask drop accident are presented in FSAR Section 14.11. For the purpose of defining the upper limit of the radiological consequences of a fuel cask drop accident, it is assumed that all 73 fuel assemblies in a 7 x 11 Westinghouse spent fuel pool rack with a minimum decay of 30 days are damaged and release their fuel rod gap inventories. Three fuel cask drop scenarios were analyzed to encompass all fuel cask drop events. They are:

1. A fuel cask drop onto 30 day decayed fuel with the Fuel Handling Area Ventilation System aligned for emergency filtration with a conservative amount of unfiltered leakage. All isolatable unfiltered leak path are assumed to be isolated prior to event initiation.

2. A fuel cask drop onto 30 day decayed fuel with the Fuel Handling Area Ventilation System aligned for emergency filtration with a conservative amount of unfiltered leakage. This scenario determined the maximum amount of non-isolatable unfiltered leakage that can exist and still meet offsite dose limits. This scenario also assumes isolation of isolable leak paths prior to event initiation.

3. A fuel cask drop onto 90 day decayed fuel without the Fuel Handling Area Ventilation System aligned for emergency filtration. This scenario needs no assumptions as to unfiltered leakage or post-accident unfiltered leak path isolation times since all radiation is assumed to be released unfiltered from the fuel handling area.

The results of the analysis show that the radiological consequences of a fuel cask drop in the spent fuel pool meet the acceptance criteria of Regulatory Guide 1.25 (Ref. 4) and NUREG-0800 Section 15.7.5 (Ref. 5) for all scenarios. In addition, the dose from all scenarios are less than 25% of the dose guidelines in 10 CFR 100. For scenario 2, the analysis shows that a maximum of 20% charcoal filter bypass from non-isolatable leak paths can be accommodated while still meeting 25% of the 10 CFR 100 guidelines.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Filtration of the fuel handling area atmosphere following a fuel handling accident is not necessary to maintain the offsite doses within the guidelines of 10 CFR 100. Thus, a total system failure would not impact the margin of safety as described in the safety analysis. However, analysis has shown that post-accident filtration by the Fuel Handling Area Ventilation System provides significant reduction in offsite doses by limiting the release of airborne radioactivity. Therefore, for the fuel handling accident, the Fuel Handling Area Ventilation System satisfies Criterion 4 of 10 CFR 50.36(c)(2).

Filtration of the fuel handling area atmosphere following a fuel cask drop on irradiated fuel assemblies with < 90 days decay is required to maintain the offsite doses within the guidelines of 10 CFR 100. Therefore, for the fuel cask drop accident, the Fuel Handling Area Ventilation System satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The LCO for the Fuel Handling Area Ventilation System ensures filtration of the fuel handling area atmosphere is immediately available in the event of a fuel handling accident, or a fuel cask drop accident. As such, the LCO requires the Fuel Handling Area Ventilation System to be OPERABLE with one fuel handling area exhaust fan aligned to the "emergency filter bank" and in operation.

The Fuel Handling Area Ventilation System is considered OPERABLE when the individual components necessary to control exposure in the fuel handling building are OPERABLE. The Fuel Handling Area Ventilation System is considered OPERABLE when:

a. One exhaust fan is aligned to the "emergency filter bank" and in operation to ensure the air discharged to the main ventilation exhaust plenum has been filtered. Operation of only one fuel handling area exhaust fan ensures the design flow rate of the "emergency filter bank" is not exceeded.

b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork and dampers are OPERABLE, and air circulation can be maintained. Inclusive to the requirement to align the "emergency filter bank" is that the "normal filter bank" is isolated by its associated inlet damper to prevent the release of unfiltered air.

BASES

APPLICABILITY

The Fuel Handling Area Ventilation System must be OPERABLE, aligned, and in operation whenever the potential exists for an accident that results in the release of radioactive material to the fuel handling area atmosphere that could exceed previously approved offsite dose limits if released unfiltered to the outside atmosphere. As such, the Fuel Handling Area Ventilation System is required; during movement of irradiated fuel assemblies in the fuel handling building when irradiated fuel assemblies with < 30 days decay time are in the fuel handling building; during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in containment when irradiated fuel assemblies with < 30 days decay time are in the containment with the equipment hatch open, and during movement of a fuel cask in or over the spent fuel pool when irradiated fuel assemblies with < 90 days decay time fuel handling building.

The requirement for the Fuel Handling Area Ventilation System does not apply during movement of irradiated fuel assemblies or CORE ALTERATIONS when all irradiated fuel assemblies in the fuel handling building, or all irradiated fuel assemblies in the containment with the equipment hatch open, have decayed for 30 days or greater since the dose consequences from a fuel handling accident would be of the same magnitude without the filters operating as the dose consequences would be with the filters operating and two days decay. In addition, the requirement for the Fuel Handling Area Ventilation System does not apply during fuel cask movement when all irradiated fuel assemblies in the fuel handling building have decayed 90 days or greater since the dose consequences remain less than 25% of the guidelines of 10 CFR 100.

ACTIONS

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

If the Fuel Handling Area Ventilation System is not aligned to the "emergency filter bank", or one exhaust fan is not in operation, or the system is inoperable for any reason, action must be taken to place the unit in a condition in which the LCO does not apply. Therefore, activities involving the movement of irradiated fuel assemblies, CORE ALTERATIONS, and movement of a fuel cask in or over the spent fuel pool, must be suspended immediately to minimize the potential for a fuel handling accident.

The suspension of fuel movement, CORE ALTERATIONS, and fuel cask movement shall not preclude the completion of placing a fuel assembly, core component, or fuel cask in a safe position.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

This SR verifies the performance of Fuel Handling Area Ventilation System filter testing in accordance with the Ventilation Filter Testing Program. The Fuel Handling Area Ventilation System filter tests are in accordance with the Regulatory Guide 1.52 (Ref. 6) as described in Ventilation Filter Testing Program. The Ventilation Filter Testing Program 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 Ventilation Filter Testing Program.

SR 3.7.12.2

This SR verifies the Fuel Handling Area Ventilation System has not degraded and is operating as assumed in the safety analysis. The flow rate is periodically tested to verify proper function of the Fuel Handling Ventilation System. When aligned to the "emergency filter bank", the Fuel Handling Area Ventilation System is designed to reduce the amount of unfiltered leakage from the fuel handling building which, in the event of a fuel handling accident, lowers the dose at the site boundary to well within the guidelines of 10 CFR 100. The Fuel Handling Area Ventilation System is designed to lower the dose to these levels at a flow rate of $\geq$ 5840 cfm and $\leq$ 8760 cfm. The Frequency of 18 months is consistent with the test for filter performance and other filtration SRs.

BASES

REFERENCES

1. FSAR, Section 9.8

2. FSAR, Section 14.11

3. FSAR, Section 14.19

4. Regulatory Guide 1.25, Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Reactors.

5. NUREG-0800 Section 15.7.5, Spent Fuel Cask Drop Accidents.

6. Regulatory Guide 1.52, Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorbtion Units of Light-Water-Cooled Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.13 Engineered Safeguards Room Ventilation (ESRV) Dampers

BASES

BACKGROUND

The ESRV Dampers isolate the safeguards rooms by closing the inlet and exhaust plenum dampers on the initiation of a high radiation alarm from their respective airborne particulate monitor. This isolation lowers the offsite dose to well within 10 CFR 100 (Ref. 1) limits if a leak should occur. Typically, high radiation would only be expected due to excessive leakage during the recirculation phase of operation following a Loss of Coolant Accident (LOCA).

The ESRV Dampers consists of two trains. Each train consists of a supply plenum damper, a exhaust plenum damper, a radiation monitor, and associated piping, valves, and ductwork. Instrumentation which is addressed in LCO 3.3.10, "Engineered Safeguards Room Ventilation (ESRV) Instrumentation," also form part of the system. The Reactor Auxiliary Building Main Ventilation System provides normal cooling in conjunction with the engineered safeguards room coolers. During emergency operations, the ESRV Dampers are shut, isolating the affected safeguards room(s) from the rest of the auxiliary building ventilation system lowering the leakage to the environment from the auxiliary building.

The ESRV Dampers are discussed in the FSAR, Sections 7.4.5.2 and 14.22, and Design Basis Document (DBD) 1.07 (Refs. 2, 3, and 4, respectively).

APPLICABLE SAFETY ANALYSES

The design basis of the ESRV Dampers is established by the Maximum Hypothetical Accident (MHA). The system evaluation assumes a failure causes leakage into the engineered safeguards rooms, such as safety injection pump seal leakage, during the recirculation mode. In such a case, the system limits the radioactive release from the engineered safeguards rooms to well within 10 CFR 100 limits (Ref. 1). The analysis of the effects and consequences of a MHA is presented in Reference 3. The ESRV Dampers may also actuate following a small break LOCA, after the plant goes into the recirculation mode of long term cooling to mitigate releases of smaller leaks, such as from valve stem packing.

The ESRV Dampers satisfies Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

Two ESRV Damper trains are required to be OPERABLE to ensure that each engineered safeguards room isolates upon receipt of its respective high radiation alarm. Total system failure could result in the atmospheric release from the engineered safeguards rooms exceeding the required limits in the event of a Design Basis Accident (DBA).

An ESRV Damper train is considered OPERABLE when its associated radiation monitor, instrumentation, ductwork, valves, and dampers are OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the ESR-Damper trains are required to be OPERABLE consistent with the OPERABILITY requirements of the Emergency Core Cooling System (ECCS).

In MODES 5 and 6, the ESRV Damper trains are not required to be OPERABLE, since the ECCS is not required to be OPERABLE.

ACTIONS

A.1

Condition A addresses the failure of one or both ESRV Damper trains. Operation may continue as long as action is immediately initiated to isolate the affected engineered safeguards room. With the inlet and exhaust dampers closed, or if the inlet and outlet ventilation plenums are adequately sealed, the engineered safeguards room is isolated and the intended safety function is achieved, since the potential pathway for radioactivity to escape to the environment from the engineered safeguards room has been minimized.

The Completion Time for this Required Action is commensurate with the importance of maintaining the engineered safeguards room atmosphere isolated from the outside environment when the ECCS pumps are circulating primary coolant after an accident.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR verifies that each ESRV Damper train closes on an actual or simulated actuation signal. The 31 day Frequency is based on operating experience which has shown that these components usually pass the SR when tested at this Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 100.11
2. FSAR, Section 7.4.5.2
3. FSAR, Section 14.22
4. Design Basis Document (DBD) 1.07, "Auxiliary Building HVAC Systems"

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pool (SFP) Water Level

BASES

BACKGROUND

The minimum water level in the SFP meets the assumptions of iodine decontamination factors following a fuel handling or cask drop 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 SFP design is given in the FSAR, Section 9.11 (Ref. 1), and the Spent Fuel Pool Cooling and Cleanup System is given in the FSAR, Section 9.4 (Ref. 2). The assumptions of fuel handling and fuel cask drop accidents are given in the FSAR, Section 14.19 and 14.11 (Refs. 3 and 4), respectively.

APPLICABLE SAFETY ANALYSES

The minimum water level in the SFP meets the assumptions of fuel handling or fuel cask drop accident analyses described in References 3 and 4 and are consistent with the assumptions of Regulatory Guide 1.25 (Ref. 5). The resultant 2 hour thyroid dose to a person at the exclusion area boundary is well within the 10 CFR 100 (Ref. 6) limits.

Reference 5 assumes there is 23 ft of water between the top of the damaged fuel assembly and the fuel pool surface for a fuel handling or fuel cask drop accident. This LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single assembly, dropped and lying horizontally on top of the spent fuel racks, there may be < 23 ft of water above the top of the assembly and the surface, by the width of the assembly. To offset this small nonconservatism, the analysis assumes that all fuel rods fail, although analysis shows that only the first few rods fail from a hypothetical maximum drop.

The SFP water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2).

BASES

LCO

The specified water level preserves the assumptions of the fuel handling or fuel cask drop accident analyses. As such, it is the minimum required for movement of fuel assemblies or movement of a fuel cask in or over the SFP.

The LCO is modified by a Note which allows SFP level to be below the 647 ft elevation to support movement of a fuel cask in or over the SFP. This is necessary due to the water displaced by the fuel cask as it is lowered or dropped into the SFP. If the SFP level is normal prior to the fuel cask entering the SFP, the SFP could overflow.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the SFP or movement of a fuel cask in or over the SFP since the potential for a release of fission products exists.

ACTIONS

The Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

If moving irradiated fuel assemblies or fuel cask in or over the SFP while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies or fuel cask in or over the SFP while in MODES 1, 2, 3, and 4, the movement of fuel or movement of a fuel cask is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies or fuel cask in or over the SFP is not sufficient reason to require a reactor shutdown.

A.1 and A.2

When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. When the SFP water level is lower than the required level, the movement of irradiated fuel assemblies in the SFP or movement of a fuel cask in or over the SFP are immediately suspended. This effectively precludes a spent fuel handling or fuel cask drop accident from occurring. This does not preclude moving a fuel assembly or fuel cask to a safe position.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies sufficient SFP water is available in the event of a fuel handling or fuel cask drop accident. The water level in the SFP must be checked periodically. The 7 day Frequency is appropriate because the volume in the pool is normally stable. Water level changes are controlled by plant procedures and are acceptable, based on operating experience.

During refueling operations, the level in the SFP is at equilibrium with that of the refueling cavity, and the level in the refueling cavity is checked daily in accordance with LCO 3.9.6, "Refueling Cavity Water Level."

REFERENCES

1. FSAR, Section 9.11
2. FSAR, Section 9.4
3. FSAR, Section 14.19
4. FSAR, Section 14.11
5. Regulatory Guide 1.25
6. 10 CFR 100.11

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Pool (SFP) Boron Concentration

BASES

BACKGROUND	As described in LCO 3.7.16, "Spent Fuel Assembly Storage," fuel assemblies are stored in the spent fuel racks in accordance with criteria based on initial enrichment and discharge burnup. Although the water in the spent fuel pool is normally borated to ≥ 1720 ppm, the criteria that limit the storage of a fuel assembly to specific rack locations is conservatively developed without taking credit for boron.
APPLICABLE SAFETY ANALYSES	A fuel assembly could be inadvertently loaded into a spent fuel rack location not allowed by LCO 3.7.16 (e.g., an unirradiated fuel assembly or an insufficiently depleted fuel assembly). This accident is analyzed assuming the extreme case of completely loading the fuel pool racks with unirradiated assemblies of maximum enrichment. Another type of postulated accident is associated with a fuel assembly that is dropped onto the fully loaded fuel pool storage rack. Either incident could have a positive reactivity effect, decreasing the margin to criticality. However, the negative reactivity effect of the soluble boron compensates for the increased reactivity caused by either one of the two postulated accident scenarios. The concentration of dissolved boron in the SFP satisfies Criterion 2 of 10 CFR 50.36(c)(2).
LCO	The specified concentration of dissolved boron in the SFP preserves the assumptions used in the analyses of the potential accident scenarios described above. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the SFP.
APPLICABILITY	This LCO applies whenever fuel assemblies are stored in the spent fuel pool until a complete spent fuel pool verification of the stored assemblies has been performed following the last movement of fuel assemblies in the spent fuel pool. This LCO does not apply following the verification since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

BASES

ACTIONS

The ACTIONS are modified by a Note indicating that LCO 3.0.3 does not apply.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

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

When the concentration of boron in the spent fuel pool is less than required, immediate action must be taken to preclude an accident from happening or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. This does not preclude the movement of fuel assemblies to a safe position. In addition, action must be immediately initiated to restore boron concentration to within limit. Alternately, beginning a verification of the SFP fuel locations to ensure proper locations of the fuel can be performed.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies that the concentration of boron in the spent fuel pool is within the required limit. As long as this SR is met, the analyzed incidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over a short period of time.

REFERENCES

None

B 3.7 PLANT SYSTEMS

B 3.7.16 Spent Fuel Assembly Storage

BASES

BACKGROUND	The spent fuel storage facility is designed to store either new (nonirradiated) nuclear fuel assemblies, or used (irradiated) fuel assemblies in a vertical configuration underwater. The storage pool is sized to store 892 irradiated fuel assemblies, which includes storage for failed fuel canisters. The spent fuel storage racks are grouped into two regions, Region I and Region II per Figure 3.7.16-1. The racks are designed as a Seismic Category I structure able to withstand seismic events. Region I contains racks in the spent fuel pool having a 10.25 inch center-to-center spacing and a single rack in the north tilt pit having an 11.25 inch by 10.69 inch center-to-center spacing. Region II contains racks in both the spent fuel pool and the north tilt pit having a 9.17 inch center-to-center spacing. Because of the smaller spacing and poison concentration, Region II racks have more limitations for fuel storage than Region I racks. Further information on these limitations can be found in Section 4.0, "Design Features." These limitations (e.g., enrichment, burnup) are sufficient to maintain a k_{eff} of $\leq$ 0.95 for spent fuel of original enrichment of up to 4.40%.
APPLICABLE SAFETY ANALYSES	The spent fuel storage facility is designed for noncriticality by use of adequate spacing, and "flux trap" construction whereby the fuel assemblies are inserted into neutron absorbing stainless steel cans. The spent fuel assembly storage satisfies Criterion 2 of 10 CFR 50.36(c)(2).
LCO	The restrictions on the placement of fuel assemblies within the spent fuel pool, according to Table 3.7.16-1, in the accompanying LCO, ensures that the k_{eff} of the spent fuel pool will always remain < 0.95 assuming the pool to be flooded with unborated water. The restrictions are consistent with the criticality safety analysis performed for the spent fuel pool according to Table 3.7.16-1, in the accompanying LCO. Fuel assemblies not meeting the criteria of Table 3.7.16-1 shall be stored in accordance with Specification 4.3.1.1.
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in Region II of either the spent fuel pool or the north tilt pit.

BASES

ACTIONS

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, in either case, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

A.1

When the configuration of fuel assemblies stored in Region II the spent fuel pool is not in accordance with Table 3.7.16-1, immediate action must be taken to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Table 3.7.16-1.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with Table 3.7.16-1 in the accompanying LCO prior to placing the fuel assembly in a Region II storage location.

REFERENCES

None

BASES

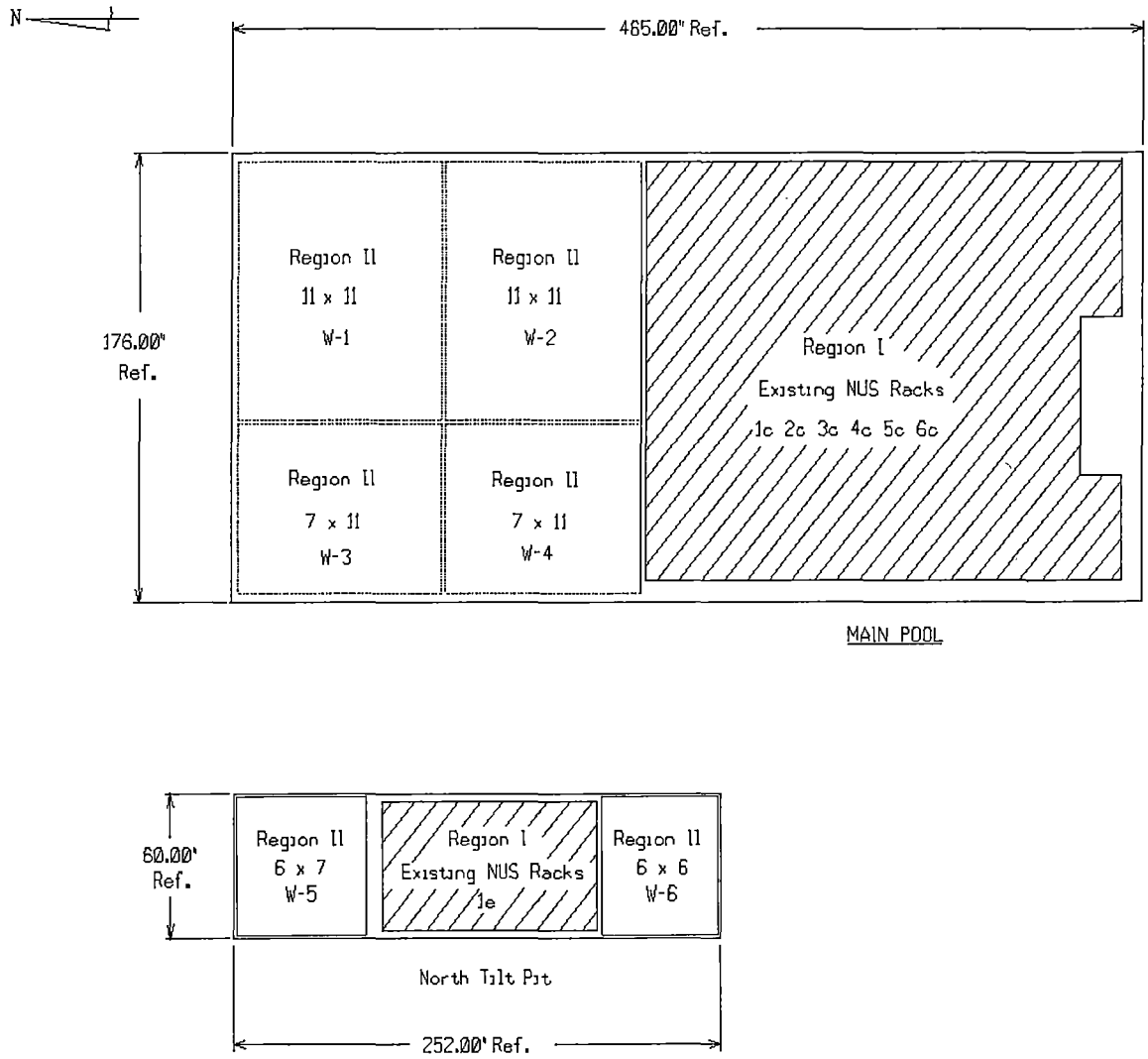

Figure B 3.7.16-1 (page 1 of 1)
Spent Fuel Arrangement

B 3.7 PLANT SYSTEMS

B 3.7.17 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Primary Coolant System (PCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives, and thus is indication of current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 1 gpm tube leak of primary coolant at the limit of 1.0 μCi/gm as assumed in the safety analyses with exception of the control rod ejection analysis which assumes 0.6 gpm. LCO 3.4.13, "PCS Operational LEAKAGE," is more restrictive in that the limit for a primary to secondary tube leak is 0.3 gpm. 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 primary coolant LEAKAGE. Most of the iodine isotopes have short half lives (i.e., < 20 hours).

Operating a plant at the allowable limits would result in a 2 hour Exclusion Area Boundary (EAB) exposure well within the 10 CFR 100 (Ref. 1) limits.

APPLICABLE SAFETY ANALYSES

The accident analysis of the Main Steam Line Break (MSLB), outside of containment as discussed in the FSAR, Chapter 14.14 (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 are well within the plant EAB limits (Ref. 1) for whole body and thyroid dose rates.

BASES

APPLICABLE SAFETY ANALYSES (continued)

With the loss of offsite power, the remaining steam generator is available for core decay heat dissipation by venting steam to the atmosphere through Main Steam Safety Valves (MSSVs) and Atmospheric Dump Valves (ADVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generator. Venting continues until the primary coolant temperature and pressure have decreased sufficiently for the Shutdown Cooling System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through MSSVs and ADVs during the event.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36(c)(2).

LCO

As indicated in the Applicable Safety Analyses, the specific activity limit in the secondary coolant system of ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 limits the radiological consequences of a Design Basis Accident (DBA) to well within 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 plant 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 PCS and steam generators are at low pressure or depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

BASES

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant is an indication of a problem in the PCS and contributes to increased post accident doses. If secondary specific activity cannot be restored to within limits in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in 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 3.7.17.1

This SR ensures that the secondary specific activity is within the limits of the accident analysis. A gamma isotope 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 primary coolant activity or LEAKAGE. The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

REFERENCES

1. 10 CFR 100.11

2. FSAR, Section 14.14

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The plant Class 1E Electrical Power Distribution System AC sources consist of the offsite power sources, and the onsite standby power sources, Diesel Generators 1-1 and 1-2 (DGs). 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 AC power system at Palisades consists of a 345 kV switchyard, three circuits connecting the plant with off-site power (station power, startup, and safeguards transformers), the on-site distribution system, and two DGs. The on-site distribution system is divided into safety related (Class 1-E) and non-safety related portions.

The switchyard interconnects six transmission lines from the off-site transmission system and the output line from the Palisades main generator. These lines are connected in a "breaker and a half" scheme between the Front (F) and Rear (R) buses such that any single off-site line may supply the Palisades station loads when the plant is shutdown.

Two circuits supplying Palisades 2400 V buses from off-site are fed directly from a switchyard bus through the startup and safeguards transformers. They are available both during operation and during shutdown. The third circuit supplies the plant loads by "back feeding" through the main generator output circuit and station power transformers after the generator has been disconnected by a motor operated disconnect.

The station power transformers are connected into the main generator output circuit. Station power transformers 1-1 and 1-2 connect to the generator 22 kV output bus. Station power transformer 1-3 connects to the generator output line on the high voltage side of the main transformer. Station power transformers 1-1 and 1-3 supply non-safety related 4160 V loads during plant power operation and during backfeeding operations. Station power transformer 1-2 can supply both safety related and non-safety related 2400 V loads during plant power operation or backfeeding operation.

BASES

BACKGROUND (continued)

The three startup transformers are connected to a common 345 kV overhead line from the switchyard R bus. Startup transformers 1-1 and 1-3 supply 4160 V non-safety related station loads; Startup Transformer 1-2 can supply both safety related and non-safety related 2400 V loads. The startup transformers are available during operation and shutdown.

Safeguards Transformer 1-1 is connected to the switchyard F bus. It feeds station 2400 V loads through an underground line. It is available to supply these loads during operation and shutdown.

The onsite distribution system consists of seven main distribution buses (4160 V buses 1A, 1B, 1F, and 1G, and 2400 V buses 1C, 1D, and 1E) and supported lower voltage buses, Motor Control Centers (MCCs), and lighting panels. The 4160 V buses and 2400 V bus 1E are not safety related. Buses 1C and 1D and their supported buses and MCCs form two independent, redundant, safety related distribution trains. Each distribution train supplies one train of engineered safety features equipment.

In the event of a generator trip, all loads supplied by the station power transformers are automatically transferred to the startup transformers. Loads supplied by the safeguards transformer are unaffected by a plant trip. If power is lost to the safeguards transformer, the 2400 V loads will automatically transfer to startup transformer 1-2. If the startup transformers are not energized when these transfers occur, their output breakers will be blocked from closing and the 2400 V safety related buses will be energized by the DGs.

The two DGs each supply one 2400 V bus. They provide backup power in the event of loss of off-site power, or loss of power to the associated 2400 V bus. The continuous rating of the DGs is 2500 kW, with 110 percent overload permissible for 2 hours in any 24 hour period. The required fuel in the Fuel Oil Storage Tank and DG Day Tank will supply one DG for a minimum period of 7 days assuming accident loading conditions and fuel conservation practices.

If either 2400 V bus, 1C or 1D, experiences a sustained undervoltage, the associated DG is started, the affected bus is separated from its offsite power sources, major loads are stripped from that bus and its supported buses, the DGs are connected to the bus, and ECCS or shutdown loads are started by an automatic load sequencer.

BASES

BACKGROUND (continued)

The DGs share a common fuel oil storage and transfer system. A single buried Fuel Oil Storage Tank is used, along with an individual day tank for each DG, to maintain the required fuel oil inventory. Two fuel transfer pumps are provided. The fuel transfer pumps are necessary for long term operation of the DGs. Testing has shown that each DG consumes about 2.6 gallons of fuel oil per minute at 2400 kW. Each day tank is required to contain at least 2500 gallons. Therefore, each fuel oil day tank contains sufficient fuel for more than 15 hours of full load (2500 kW) operation. Beyond that time, a fuel transfer pump is required for continued DG operation.

Either fuel transfer pump is capable of supplying either DG. However, each fuel transfer pump is not capable, with normally available switching, of being powered from either DG. DG 1-1 can power either fuel transfer pump, but DG 1-2 can only power P-18A. The fuel oil pumps share a common fuel oil storage tank, and common piping.

Fuel transfer pump P-18A is powered from MCC-8, which is normally connected to Bus 1D (DG 1-2) through Station Power Transformer 12 and Load Center 12. In an emergency, P-18A can be powered from Bus 1C (DG 1-1) by cross connecting Load Centers 11 and 12.

Fuel transfer pump P-18B is powered from MCC-1, which is normally connected to Bus 1C (DG 1-1) through Station Power Transformer 19 and Load Center 19. P-18B cannot be powered, using installed equipment, from Bus 1D (DG 1-2).

APPLICABLE SAFETY ANALYSES

The safety analyses do not explicitly address AC electrical power. They do, however, assume that the Engineered Safety Features (ESF) are available. The OPERABILITY of the ESF functions is supported by the AC Power Sources.

The design requirements are for each assumed safety function to be available under the following conditions:

a. The occurrence of an accident or transient,

b. The resultant consequential failures,

c. A worst case single active failure,

d. Loss of all offsite or all onsite AC power, and

e. The most reactive control rod fails to insert.

BASES

APPLICABLE SAFETY ANALYSES (continued)

One proposed mechanism for the loss of off-site power is a perturbation of the transmission grid because of the loss of the plant's generating capacity. A loss of off-site power as a result of a generator trip can only occur during MODE 1 with the generator connected to the grid. However, it is also assumed in analysis for some events in MODE 2, such as a control rod ejection. No specific mechanism for initiating a loss of off-site power when the plant is not on the line is discussed in the FSAR.

In most cases, it is conservative to assume that off-site power is lost concurrent with the accident and that the single failure is that of a DG. That would leave only one train of safeguards equipment to cope with the accident, the other being disabled by the loss of AC power. Those analyses which assume that a loss of off-site power and failure of a single DG accompany the accident assume 11 seconds from the loss of power until the bus is re-energized. This time includes time for all portions of the circuitry necessary for detecting the undervoltage (relays and auxiliary relays) and starting the DG. Included in the 11 seconds, the analyses also assume 10 seconds for the DG to start and connect to the bus, and additional time for the sequencer to start each safeguards load.

The same assumptions are not conservative for all accident analyses. When analyzing the effects of a steam or feed line break, the loss of the condensate and feedwater pumps would reduce the steam generator inventory, so a loss of off-site power is not assumed.

In MODE 5 and MODE 6, loss of off-site power can be considered as an initiating event for a loss of shutdown cooling event.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power Distribution System and an independent DG for each safeguards train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence or a postulated DBA.

BASES

LCO (continued)

General Design Criterion 17 (Ref. 1) requires, in part, that: "Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions."

The qualified offsite circuits available are Safeguards Transformer 1-1 and Startup Transformer 1-2. Station Power Transformer 1-2 is not qualified as a required source for LCO 3.8.1 since it is not independent of the other two offsite circuits. This LCO does not prohibit use of Station Power Transformer to power the 2400 V safety related buses, but the two qualified sources must be OPERABLE.

Each offsite circuit must be capable of maintaining acceptable frequency and voltage, and accepting required loads during an accident, while supplying the 2400 V safety related buses.

Following a loss of offsite power, each DG must be capable of starting and connecting to its respective 2400 V bus. This will be accomplished within 10 seconds after receipt of a DG start signal. 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 2400 V safety related buses.

Proper sequencing of loads and tripping of nonessential loads are required functions for DG OPERABILITY.

APPLICABILITY

The AC sources are required to be OPERABLE above MODE 5 to ensure that redundant sources of off-site and on-site AC power are available to support engineered safeguards equipment in the event of an accident or transient. The AC sources also support the equipment necessary for power operation, plant heatups and cooldowns, and shutdown operation.

The AC source requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are addressed in LCO 3.8.2, "AC Sources - Shutdown."

BASES

ACTIONS

A.1

To ensure a highly reliable power source remains with the 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

According to the recommendations of Regulatory Guide (RG) 1.93 (Ref. 2), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single continuous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 7 days (for a total of 17 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 10 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

BASES

ACTIONS (continued)

B.1

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

B.2

In accordance with LCO 3.0.6, the requirement to declare required features inoperable carries with it the requirement to take those actions required by the LCO for that required equipment.

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features with a train redundant to the train that has an inoperable DG.

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 Completion 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 on the other train is inoperable.

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

Discovering one required DG inoperable coincident with one or more inoperable required supporting or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for Required Action B.2. Four hours from the discovery of these events existing concurrently, is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

BASES

ACTIONS

B.2 (continued)

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

The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3 provides an allowance to avoid unnecessary testing of the OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 (test starting of the OPERABLE DG) 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 to not exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing Required Action B.3.1 or B.3.2 the corrective action system would normally 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. 3), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

BASES

ACTIONS (continued)

B.4

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System for a limited period. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 13 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 10 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

BASES

ACTIONS (continued)

C.1

In accordance with LCO 3.0.6 the requirement to declare required features inoperable carries with it the requirement to take those actions required by the LCO for that required equipment.

Required Action C.1, which applies when two required offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours. The rationale for the reduction to 12 hours is that RG 1.93 (Ref. 2) recommends a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains.

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 Completion 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.

C.2

According to the recommendations of RG 1.93 (Ref. 2), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to accomplish 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.

BASES

ACTIONS

C.2 (continued)

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the plant in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single 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.

If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition D to provide the requirements for the loss of one offsite circuit and one DG without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. 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.

According to the recommendations of RG 1.93 (Ref. 2), operation may continue in Condition D for a period that should not exceed 12 hours.

BASES

ACTIONS (continued)

E.1

With both DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, no AC source would be available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a 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 an inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to the recommendations of RG 1.93 (Ref. 2), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC power sources cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to an operating condition 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.

G.1

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

BASES

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 4). 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 RG 1.9 (Ref. 5) and RG 1.137 (Ref. 6).

Where the SRs discussed herein specify voltage and frequency tolerances for the DGs operated in the "Unit" mode, the following is applicable. The minimum steady state output voltage of 2280 V is 95% of the nominal 2400 V generator rating. This value is above the setting of the primary undervoltage relays (127-1 and 127-2) and above the minimum analyzed acceptable bus voltage. It also allows for voltage drops to motors and other equipment down through the 120 V level. The specified maximum steady state output voltage of 2520 V is 105% of the nominal generator rating of 2400 V. It is below the maximum voltage rating of the safeguards motors, 2530 V. The specified minimum and maximum frequencies of the DG are 59.5 Hz and 61.2 Hz, respectively. The minimum value assures that ESF pumps provide sufficient flow to meet the accident analyses. The maximum value is equal to 102% of the 60 Hz nominal frequency and is derived from the recommendations given in RG 1.9 (Ref. 5).

Higher maximum tolerances are specified for final steady state voltage and frequency following a loss of load test, because that test must be performed with the DG controls in the "Parallel" mode. Since "Parallel" mode operation introduces both voltage and speed droop, the DG final conditions will not return to the nominal "Unit" mode settings.

SR 3.8.1.1

This SR assures that the required offsite circuits are OPERABLE. Each offsite circuit must be energized from associated switchyard bus through its disconnect switch to be OPERABLE.

Since each required offsite circuit transformer has only one possible source of power, the associated switchyard bus, and since loss of voltage to either the switchyard bus or the transformer is alarmed in the control room, correct alignment and voltage may be verified by the absence of these alarms.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

The 7 day Frequency is adequate because disconnect switch positions cannot change without operator action and because their status is displayed in the control room.

SR 3.8.1.2

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

The monthly test starting of the DG provides assurance that the DG would start and be ready for loading in the time period assumed in the safety analyses. The monthly test, however does not, and is not intended to, test all portions of the circuitry necessary for automatic starting and loading. The operation of the bus undervoltage relays and their auxiliary relays which initiate DG starting, the control relay which initiates DG breaker closure, and the DG breaker closure itself are not verified by this test. Verification of automatic operation of these components requires de-energizing the associated 2400 V bus and cannot be done during plant operation. For this test, the 10 second timing is started when the DG receives a start signal, and ends when the DG voltage sensing relays actuate. For the purposes of SR 3.8.1.2, the DGs are manually started from standby conditions. Standby conditions for a DG mean the diesel engine is not running, its coolant and oil temperatures are being maintained consistent with manufacturer recommendations, and ≥ 20 minutes have elapsed since the last DG air roll.

Three relays sense the terminal voltage on each DG. These relays, in conjunction with a load shedding relay actuated by bus undervoltage, initiate automatic closing of the DG breaker. During monthly testing, the actuation of the three voltage sensing relays is used as the timing point to determine when the DG is ready for loading.

The 31 day Frequency for performance of SR 3.8.1.2 agrees with the original licensing basis for the Palisades plant.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 for at least 15 minutes. A minimum total run time of 60 minutes is required to stabilize engine temperatures.

During the period when the DG is paralleled to the grid, it must be considered inoperable. This is because the load shedding circuits, which are actuated by the 2400 V bus undervoltage relays and which must function to initiate automatic DG loading, are blocked when the DG breaker is closed. This load shed block assures that a spurious undervoltage will not cause load shedding while a DG is the sole source for accident loads, but it prevents automatic DG actuation while the DG is paralleled to the grid.

The 31 day Frequency for this Surveillance is consistent with the original Palisades licensing basis.

The SR is modified by three Notes. Note 1 states that momentary transients outside the required band do not invalidate this test. This is to assure that a minor change in grid conditions and the resultant change in DG load, or a similar event, does not result in a surveillance being unnecessarily repeated. Note 2 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 3 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The specified level is adequate for a minimum of 15 hours of DG operation at full load.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.5

Each DG is provided with an engine overspeed trip to prevent damage to the engine. 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. This Surveillance may be accomplished with the DG in the "Parallel" mode.

An acceptable method is to parallel the DG with the grid and load the DG to a load equal to or greater than its single largest post-accident load. The DG breaker is tripped while its voltage and frequency (or speed) are being recorded. The time, voltage, and frequency tolerances specified in this SR are derived from the recommendations of RG 1.9, Revision 3 (Ref. 5).

RG 1.9 recommends that the increase in diesel speed during the transient does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. The Palisades DGs have a synchronous speed of 900 rpm and an overspeed trip setting range of 1060 to 1105 rpm. Therefore, the maximum acceptable transient frequency for this SR is 68 Hz.

The minimum steady state voltage is specified to provide adequate margin for the switchgear and for both the 2400 and 480 V safeguards motors; the maximum steady state voltage is 2400 +10% V as recommended by RG 1.9.

The minimum acceptable frequency is specified to assure that the safeguards pumps powered from the DG would supply adequate flow to meet the safety analyses. The maximum acceptable steady state frequency is slightly higher than the +2% (61.2 Hz) recommended by RG 1.9 because the test must be performed with the DG controls in the Parallel mode. The increased frequency allowance of 0.3 Hz is based on the expected speed differential associated with performance of the test while in the "Parallel" mode.

The 18 month surveillance Frequency is consistent with the recommendation of RG 1.9 (Ref. 5).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine and generator load response under a complete loss of load. These acceptance criteria provide DG damage protection. The 4000 V limitation is based on generator rating of 2400/4160V and the ratings of those components (connecting cables and switchgear) which would experience the voltage transient. 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 re-connection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, yet still provide adequate testing margin between the specified power factor limit and the DG design power factor limit of 0.8, testing must be performed using a power factor $\leq$ 0.9. This is consistent with RG 1.9 (Ref. 5).

The 18 month Frequency is consistent with the recommendation of RG 1.9 and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.7

As recommended by RG 1.9 (Ref. 5) this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and re-energizing of the emergency buses and respective loads from the DG.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

The requirement to energize permanently connected loads is met when the DG breaker closes, energizing its associated 2400 V bus. Permanently connected loads are those which are not disconnected from the bus by load shedding relays. They are energized when the DG breaker closes. It is not necessary to monitor each permanently connected load. The DG auto-start and breaker closure time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. For this test, the 10 second timing is started when the DG receives a start signal, and ends when the DG breaker closes. The safety analyses assume 11 seconds from the loss of power until the bus is re-energized.

The requirement to verify that auto-connected shutdown loads are energized refers to those loads which are actuated by the Normal Shutdown Sequencer. Each load should be started to assure that the DG is capable of accelerating these loads at the intervals programmed for the Normal Shutdown Sequence. The sequenced pumps may be operating on recirculation flow.

The requirements to maintain steady state voltage and frequency apply to the "steady state" period after all sequenced loads have been started. This period need only be long enough to achieve and measure steady voltage and frequency.

The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved. The requirement to supply permanently connected loads for ≥ 5 minutes, refers to the duration of the DG connection to the associated safeguards bus. It is not intended to require that sequenced loads be operated throughout the 5 minute period. It is not necessary to monitor each permanently connected load.

The requirement to verify the connection and supply of permanently and automatically connected loads is intended to demonstrate the DG loading logic. This testing may be accomplished in any series of sequential, overlapping, or total steps so that the required connection and loading sequence is verified.

The Frequency of 18 months is consistent with the recommendations of RG 1.9 (Ref. 5).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (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.

SR 3.8.1.8

RG 1.9 (Ref. 5) recommends demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 100 minutes of which is at a load above its analyzed peak accident loading and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The 100 minutes required by the SR satisfies the intent of the recommendations of the RG, but allows some tolerance between the time requirement and the DG rating. Without this tolerance, the load would have to be reduced at precisely 2 hours to satisfy the SR without exceeding the manufacturer's rating of the DG.

The DG starts for this Surveillance can be performed either from standby or hot conditions.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, yet still provide adequate testing margin between the specified power factor limit and the DG design power factor limit of 0.8, testing must be performed using a power factor of ≤ 0.9. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

In addition, a Note to the SR states that momentary transients outside the required band do not invalidate this test. This is to assure that a minor change in grid conditions and the resultant change in DG load, or a similar event, does not result in a surveillance being unnecessarily repeated.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

During the period when the DG is paralleled to the grid, it must be considered inoperable. This is because the load shedding circuits, which are actuated by the 2400 V bus undervoltage relays and which must function to initiate automatic DG loading, are blocked when the DG breaker is closed. This load shed block assures that a spurious undervoltage will not cause load shedding while a DG is the sole source for accident loads, but it prevents automatic DG actuation while the DG is paralleled to the grid.

The 18 month Frequency is consistent with the recommendations of RG 1.9 (Ref. 5).

SR 3.8.1.9

As recommended by RG 1.9 (Ref. 5), this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready to load status when offsite power is restored. The test is performed while the DG is supplying its associated 2400 V bus, but not necessarily carrying the sequenced accident loads. 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, the automatic load sequencer is reset, and the DG controls are returned to "Unit."

During the period when the DG is paralleled to the grid, it must be considered inoperable. This is because the load shedding circuits, which are actuated by the 2400 V bus undervoltage relays and which must function to initiate automatic DG loading, are blocked when the DG breaker is closed. This load shed block assures that a spurious undervoltage will not cause load shedding while a DG is the sole source for accident loads, but it prevents automatic DG actuation while the DG is paralleled to the grid.

The Frequency of 18 months is consistent with the recommendations of RG 1.9 (Ref. 3).

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

If power is lost to bus 1C or 1D, loads are sequentially connected to the bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs by concurrent motor starting currents. The 0.3 second load sequence time tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and ensures that safety analysis assumptions regarding ESF equipment time delays are met. Logic Drawing E-17 Sheet 4 (Ref. 7) provides a summary of the automatic loading of safety related buses.

The Frequency of 18 months is consistent with the recommendations of RG 1.9 (Ref. 5), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. 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.

SR 3.8.1.11

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, PCS, and containment design limits are not exceeded.

The requirement to energize permanently connected loads is met when the DG breaker closes, energizing its associated 2400 V bus. Permanently connected loads are those which are not disconnected from the bus by load shedding relays. They are energized when the DG breaker closes. It is not necessary to monitor each permanently connected load. The DG auto-start and breaker closure time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. For this test, the 10 second timing is started when the DG receives a start signal, and ends when the DG breaker closes. The safety analyses assume 11 seconds from the loss of power until the bus is re-energized.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

In addition, a Note to the SR states that momentary transients outside the required band do not invalidate this test. This is to assure that a minor change in grid conditions and the resultant change in DG load, or a similar event, does not result in a surveillance being unnecessarily repeated.

The requirement to verify that auto-connected shutdown loads are energized refers to those loads which are actuated by the DBA Sequencer. Each load should be started to assure that the DG is capable of accelerating these loads at the intervals programmed for the DBA Sequence. Since the containment spray pumps do not actuate on SIS generated by Pressure Low Pressure, the test should be performed such that spray pump starting by the sequencer is also verified along with the other SIS loads. The sequenced pumps may be operating on recirculation flow or in other testing modes. The requirements to maintain steady state voltage and frequency apply to the "steady state" period after all sequenced loads have been started. This period need only be long enough to achieve and measure steady voltage and frequency.

The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved. The requirement to supply permanently connected loads for ≥ 5 minutes, refers to the duration of the DG connection to the associated 2400 V bus. It is not intended to require that sequenced loads be operated throughout the 5 minute period. It is not necessary to monitor each permanently connected load.

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

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.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17
2. Regulatory Guide 1.93, December 1974
3. Generic Letter 84-15, July 2, 1984
4. 10 CFR 50, Appendix A, GDC 18
5. Regulatory Guide 1.9, Rev. 3, July 1993
6. Regulatory Guide 1.137, Rev. 1, October 1979
7. Palisades Logic Drawing E-17, Sheet 4

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 safety analyses do not explicitly address electrical power. They do, however, assume that various electrically powered and controlled equipment is available. Electrical power is necessary to terminate and mitigate the effects of many postulated events which could occur in MODES 5 and 6.

Analyzed events which might occur during MODES 5 and 6 are Loss of PCS inventory or Loss of PCS Flow, (which in MODES 5 and 6 would be grouped as a Loss of Shutdown Cooling event), and radioactive releases (Fuel Handling Accident, Cask Drop, Radioactive Gas Release, Etc.).

In general, when the plant is shut down, the Technical Specifications requirements ensure that the plant 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 above MODE 5 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the primary coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced, and in minimal consequences.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO requires one offsite circuit to be OPERABLE. One OPERABLE offsite circuit ensures that all required loads may be powered from offsite power. Since only one offsite AC source is required, independence is not a criterion. Any of the three offsite supplies, Safeguards Transformer 1-1, Station Power Transformer 1-2, or Startup Transformer 1-2 is acceptable as a qualified circuit.

BASES

LCO (continued)

An OPERABLE DG, associated with a 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 plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and loss of shutdown cooling).

The DG must be capable of starting, accelerating to rated speed and voltage, connecting to its respective 2400 V bus on detection of bus undervoltage, and accepting required loads. Proper "Normal Shutdown" loading sequence, and tripping of nonessential loads, is a required function for DG OPERABILITY. A Service Water Pump must be started soon after the DG to assure continued DG operability. The DBA loading sequence is not required to be OPERABLE since the Safety Injection Signal is disabled during MODES 5 and 6.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies provide assurance that equipment and instrumentation is available to:

a. Provide coolant inventory makeup,

b. Mitigate a fuel handling accident,

c. Mitigate shutdown events that can lead to core damage, and

d. Monitor and maintain the plant in a cold shutdown condition or refueling condition.

This LCO is applicable during movement of irradiated fuel assemblies even if the plant is in a condition other than MODES 5 and 6. This LCO provides the necessary ACTIONS if the AC electrical power sources required by this LCO become unavailable during movement of irradiated fuel assemblies.

The AC source requirements for MODES 1, 2, 3, and 4 are addressed in LCO 3.8.1, "AC Sources - Operating."

BASES

ACTIONS

A.1

An offsite circuit would be considered inoperable if it were not available to supply the 2400 V safety related bus or buses required by LCO 3.8.10. Since the required offsite AC source is only required to support features required by other LCOs, the option to declare those required features with no offsite power available to be inoperable, assures that appropriate ACTIONS will be implemented in accordance with the affected LCOs.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

Required Action A.1 may involve undesired and unnecessary administrative efforts, therefore, Required Action A.2.1 through A.2.4 provide alternate, but sufficiently conservative, actions.

With the required DG inoperable, the minimum required diversity of AC power sources is not available.

Required Actions A.2.1 through A.2.4, and B.1 through B.4 require suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions. The suspension of CORE ALTERATIONS and movement of irradiated fuel assemblies does not preclude actions to place a fuel assembly in a safe location; the suspension of positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SHUTDOWN MARGIN is maintained.

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 plant safety systems.

The Completion Time of "immediately" is consistent with the required times for actions requiring prompt attention. The restoration of the required AC power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in MODES 5 and 6.

The SRs from LCO 3.8.1 which are required are those which both support a feature required in MODES 5 and 6 and which can be performed without affecting the OPERABILITY or reliability of the required sources.

With only one DG available, many tests cannot be performed since their performance would render that DG inoperable during the test. This is the case for tests which require DG loading: SRs 3.8.1.3, 3.8.1.5, 3.8.1.6, 3.8.1.7, 3.8.1.8, 3.8.1.9, 3.8.1.10, and 3.8.1.11.

REFERENCES None

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel, Lube Oil, and Starting Air

BASES

BACKGROUND

The Diesel Generators (DGs) are provided with a storage tank having a required fuel oil inventory sufficient to operate one diesel for a period of 7 days, while the DG is supplying maximum post-accident loads. This onsite fuel oil capacity is sufficient to operate the DG for longer than the time to replenish the onsite supply from offsite sources.

Fuel oil is transferred from the Fuel Oil Storage Tank to either day tank by either of two Fuel Transfer Systems. The fuel oil transfer system which includes fuel transfer pump P-18A can be powered by offsite power, or by either DG. However, the fuel oil transfer system which includes fuel transfer pump P-18B can only be powered by offsite power, or by DG 1-1.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide (RG) 1.137 (Ref. 1) addresses the recommended fuel oil practices as supplemented by ANSI N195-1976 (Ref. 2).

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 onsite storage in addition to the engine oil sump is sufficient to ensure 7 days of continuous operation. This supply is sufficient supply to allow the operator to replenish lube oil from offsite sources. Implicit in this LCO is the requirement to assure, though not necessarily by testing, the capability to transfer the lube oil from its storage location to the DG oil sump, while the DG is running.

Each DG is provided with an associated starting air subsystem to assure independent start capability. The starting air system is required to have a minimum capacity with margin for a DG start attempt without recharging the air start receivers.

BASES

APPLICABLE SAFETY ANALYSES

A description of the Safety Analyses applicable in MODES 1, 2, 3, and 4 is provided in the Bases for LCO 3.8.1, "AC Sources - Operating"; during MODES 5 and 6, in the Bases for LCO 3.8.2, "AC Sources - Shutdown." Since diesel fuel, lube oil, and starting air subsystems support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full accident load operation. It is also required to meet specific standards for quality. The specified 7 day requirement and the 6 day quantity listed in Condition A are taken from the Engineering Analysis associated with Event Report E-PAL-93-026B. Additionally, the ability to transfer fuel oil from the storage tank to each day tank is required from each of the two transfer pumps.

Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full accident load for 7 days. This requirement is in addition to the lube oil contained in the engine sump. The specified 7 day requirement and the 6 day quantity listed in Condition B are based on an assumed lube oil consumption of 0.8 to 1.0% of fuel oil consumption.

The starting air subsystem must provide, without the aid of the refill compressor, sufficient air start capacity, including margin, to assure start capability for its associated DG.

These requirements, in conjunction with an ability to obtain replacement supplies within 7 days, support the availability of the DGs. DG day tank fuel requirements are addressed in LCOs 3.8.1 and 3.8.2.

APPLICABILITY

DG OPERABILITY is required by LCOs 3.8.1 and 3.8.2 to ensure the availability of the required AC power to shut down the reactor and maintain it in a safe shutdown condition following a loss of off-site power. Since diesel fuel, lube oil, and starting air support LCOs 3.8.1 and 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits, and the fuel transfer system is required to be OPERABLE, when either DG is required to be OPERABLE.

BASES

ACTIONS

A.1

In this Condition, the available DG fuel oil supply is less than the required 7 day supply, but enough for at least 6 days. This condition allows sufficient time to obtain additional fuel and to perform the sampling and 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 inventory prior to declaring the DGs inoperable.

B.1

In this Condition, the available DG lube oil supply in storage is less than the required 7 day supply, but enough for at least 6 days. This condition allows sufficient time to obtain additional lube oil. A period of 48 hours is considered sufficient to complete restoration of the required inventory prior to declaring the DGs inoperable.

C.1, D.1, and E.1

Since DG 1-2 cannot power fuel transfer pump P-18B, without P-18A, DG 1-2 becomes dependant on offsite power or DG 1-1 for its fuel supply (beyond the 15 hours it will operate on the day tank), and does not meet the requirement for independence. Since the condition is not as severe as the DG itself being inoperable, 15 hours is allowed to restore the fuel transfer system to operable status prior to declaring the DG inoperable.

Without P-18B, either DG can still provide power to the remaining fuel transfer system. Therefore, neither DG is directly affected. Continued operation with a single remaining fuel transfer system, however, must be limited since an additional single active failure (P-18A) could disable the onsite power system. Because the loss of P-18B is less severe than the loss of one DG, a 7 day Completion Time is allowed.

If both fuel transfer systems are inoperable, the onsite AC sources are limited to about 15 hours duration. Since this condition is not as severe as both DGs being inoperable, 8 hours is allowed to restore one fuel transfer pump to OPERABLE status.

BASES

ACTIONS (continued)

F.1

With the stored fuel oil properties, other than viscosity, and water and sediment, defined in the Fuel Oil Testing Program not within the required limits, but acceptable for short term DG operation, a period of 30 days is allowed for restoring the stored fuel oil properties. The most likely cause of stored fuel oil becoming out of limits is the addition of new fuel oil with properties that do not meet all of the limits. This 30 day period provides sufficient time to determine if new fuel oil, when mixed with stored fuel oil, will produce an acceptable mixture, or if other methods to restore the stored fuel oil properties are required. 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.

G.1

With a Required Action and associated Completion Time not met, or with diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A, B, or F, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

In the event that diesel fuel oil with viscosity, or water and sediment is out of limits, this would be unacceptable for even short term DG operation. Viscosity is important primarily because of its effect on the handling of the fuel by the pump and injector system; water and sediment provides an indication of fuel contamination. When the fuel oil stored in the Fuel Oil Storage Tank is determined to be out of viscosity, or water and sediment limits, the DGs must be declared inoperable, immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tank to support either DG's operation for 7 days at full post-accident load. The 7 day period is sufficient time to place the plant in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 24 hour Frequency is specified to ensure that a sufficient supply of fuel oil is available, since the Fuel Oil Storage Tank is the fuel oil supply for the diesel fire pumps, heating boilers, and rad waste evaporators, in addition to the DGs.

SR 3.8.3.2

This Surveillance ensures that sufficient stored lube oil inventory is available to support at least 7 days of full accident load operation for one DG. The 200 gallons requirement is based on an estimated consumption of 0.8 to 1.0% of fuel oil consumption.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil and stored fuel oil are of the appropriate grade and have not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion.

Testing for viscosity, specific gravity, and water and sediment is completed for fuel oil delivered to the plant prior to its being added to the Fuel Oil Storage Tank. Fuel oil which fails the test, but has not been added to the Fuel Oil Storage Tank does not imply failure of this SR and requires no specific action. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tank without concern for contaminating the entire volume of fuel oil in the storage tank.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

Fuel oil is tested for other of the parameters specified in ASTM D975 (Ref. 3) in accordance with the Fuel Oil Testing Program required by Specification 5.5.11. Fuel oil determined to have one or more measured parameters, other than viscosity or water and sediment, outside acceptable limits will be evaluated for its effect on DG operation. Fuel oil which is determined to be acceptable for short term DG operation, but outside limits will be restored to within limits in accordance with LCO 3.8.3 Condition F.

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 pressure specified in this SR is intended to reflect the acceptable margin from which successful starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

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 Oil Storage Tank once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it reduces 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 from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies and acceptance criteria are established in the Fuel Oil Testing Program based, in part, on those recommended by RG 1.137 (Ref. 1). This SR is for preventative maintenance.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.5 (continued)

The presence of water does not necessarily represent failure of this SR provided the accumulated water is removed in accordance with the requirements of the Fuel Oil Testing Program.

SR 3.8.3.6

This SR demonstrates that each fuel transfer pump and the fuel transfer system controls operate and control transfer of fuel from the Fuel Oil Storage Tank to each day tank and engine mounted tank. This is required to support continuous operation of standby power sources.

This SR provides assurance that the following portions of the fuel transfer system is OPERABLE:

a. Fuel Transfer Pumps;

b. Day and engine mounted tank filling solenoid valves; and

c. Day and engine mounted tank automatic level controls.

The 92 day Frequency corresponds to the testing requirements for pumps in the ASME Code, Section XI (Ref. 4). Additional assurance of fuel transfer system OPERABILITY is provided during the monthly starting and loading tests for each DG when the fuel oil system will function to maintain level in the day and engine mounted tanks.

REFERENCES

1. Regulatory Guide 1.137

2. ANSI N195-1976, Appendix B

3. ASTM Standards, D975, Table 1

4. ASME, Boiler and Pressure Vessel Code, Section XI

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC power system with control power. It also provides control power to selected safety related equipment and power to the preferred AC Buses (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure.

The 125 V DC electrical power system consists of two independent and redundant safety related Class 1E DC power sources. Each DC source consists of one 125 V battery, one battery charger, and the associated control equipment and interconnecting cabling. While each station battery has two associated battery chargers, one powered by the associated AC power distribution system (the directly connected chargers), and one powered from the opposite AC power distribution system (the cross connected chargers), the cross connect chargers are not required to be OPERABLE and cannot be credited to meet this LCO. The battery chargers are normally operated in pairs, either both direct connected chargers or both cross connected chargers, to assure a diverse AC supply.

During normal operation, the 125 V DC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power from the battery charger, the DC load continues to be powered from the station batteries.

The DC power distribution system is described in the Bases for LCO 3.8.9, "Distributions System - Operating."

Each battery has adequate storage capacity to carry the required load continuously for at least 4 hours and to perform three complete cycles of intermittent loads discussed in the FSAR, Chapter 8 (Ref. 2).

Each 125 V battery is separately housed in a ventilated room apart from its charger and distribution centers. Each DC source is separated physically and electrically from the other DC source to ensure that a single failure in one source does not cause a failure in a redundant source.

BASES

BACKGROUND (continued)

The batteries for the DC power sources 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 voltage limit is 2.13 V per cell, which corresponds to a total minimum voltage output of 125.7 V per battery discussed in the FSAR, Chapter 8 (Ref. 2). The criteria for sizing large lead storage batteries are defined in IEEE-485 (Ref. 3).

Each DC electrical power source has ample power output capacity for the steady state operation of connected loads during normal operation, while at the same time maintaining its battery fully charged. Each battery charger also has sufficient capacity to restore the battery from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads discussed in the FSAR, Chapter 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

A description of the Safety Analyses applicable in MODES 1, 2, 3, and 4 is provided in the Bases for LCO 3.8.1, "AC Sources - Operating."

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The DC power sources, each consisting of one battery, one directly connected battery charger and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of DC control power and Preferred AC power to shut down the reactor and maintain it in a safe condition.

An OPERABLE DC electrical power source requires its battery to be OPERABLE and connected to the associated DC bus. In order for the battery to remain OPERABLE, one charger must be in service.

The LCO requires chargers ED-15 and ED-16 because those chargers are powered by the AC power distribution system and DG associated with the battery they supply. If only the cross connected chargers were available, and a loss of off-site power should occur concurrently with the loss of one DG, both safeguards trains would eventually become disabled. One train would be disabled by the lack of AC motive power; the other would become disabled when the battery, whose only OPERABLE charger is fed by the failed DG, became depleted.

BASES

LCO (continued)

The required chargers, ED-15 and ED-16, must be OPERABLE, but need not actually be in service because the probability of a concurrent loss of offsite power with loss of one DG is low, and battery charging current is not needed immediately after an accident.

APPLICABILITY

The DC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that redundant sources of DC power are available to support engineered safeguards equipment and plant instrumentation in the event of an accident or transient. The DC sources also support the equipment and instrumentation necessary for power operation, plant heatups and cooldowns, and shutdown operation.

The DC source requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are addressed in LCO 3.8.5, "DC Sources - Shutdown."

ACTIONS

A.1 and A.2

With one of the required chargers (ED-15 or ED-16) inoperable, the cross-connected charger must be placed in service within 2 hours, if it is not already in service, to maintain the battery in OPERABLE status. If the cross-connect charger is not placed in service within 2 hours, Condition C would be entered.

Additionally for the cross-connected charger to be considered "functional," the cross-connected charger must have been surveilled and satisfied the same performance test required for the directly connected charger (i.e., SR 3.8.4.6) within the required Frequency.

In order to limit the time when the DC source is not capable of continuously meeting the single failure criterion, the required charger must be restored to OPERABLE status within 7 days.

The 7 day completion time was chosen to allow trouble shooting, location of parts, and repair.

BASES

ACTIONS (continued)

B.1 and B.2

With one battery inoperable, the associated DC system cannot meet its design. It lacks both the surge capacity and the independence from AC power sources which the battery provides if offsite power is lost. Placing the second battery charger in service provides two benefits: 1) restoration of the capacity to supply a sudden DC power demand, and 2) restoration of adequate DC power in the affected train as soon as either AC power distribution system is re-energized following a loss of offsite power. If the cross-connect charger is not placed in service within 2 hours, Condition C would be entered. Additionally for the cross-connected charger to be considered "functional," the cross-connected charger must have been surveilled and satisfied the same performance test required for the directly connected charger (i.e., SR 3.8.4.6) within the required Frequency.

In order to restore the DC source to its design capability, the battery must be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is a feature of the original Palisades licensing basis and reflects the availability to provide two trains of DC power from either AC distribution system. Furthermore, it provides a reasonable time to assess plant status as a function of the inoperable DC electrical power source and, if the battery is not restored to OPERABLE status, to prepare to effect an orderly and safe plant shutdown.

C.1 and C.2

If the inoperable DC electrical power source cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to an operating condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous current required to overcome the internal losses of a battery and maintain the battery in a fully charged state. The specified voltage is the nominal rating of the battery. At that terminal voltage, the battery has sufficient charge to provide the analyzed capacity for either accident loading or station blackout loading. The 7 day Frequency is consistent with manufacturer and IEEE-450 (Ref. 4) recommendations.

SR 3.8.4.2

Visual inspection to detect corrosion of the battery terminals and connectors, or measurement of the resistance of each inter-cell and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The specified limits of ≤ 50 µohm for inter-cell connections and terminal connections, and ≤ 360 µohms for inter-tier and inter-rack connections are in accordance with the manufacturers recommendations.

The 50 µohm value is based on the minimum battery design voltage. Battery sizing calculations show the first minute load on the ED-02 battery as the load that determines battery size, hence, battery voltage will be at its lowest value while the battery supplies this current. Calculations also show that at a minimum temperature and end of life (80% battery performance), battery voltage during this first minute load will be about 1.815 V per cell, assuming nominal connection resistance. But if all the connections were at the ceiling value of 50 µohms, the battery manufacturer indicates that the additional voltage drop would result in a battery voltage of about 1.79 V per cell, which is still above the minimum design voltage (Ref. 5).

The 360 µohm value is based on 120% of the nominal cumulative resistance of the components which make up the connections: resistance of the connecting cable, and for each end of the cable, the battery post to cable lug connection, the cable lug itself, and the lug to cable connection.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

The resistance values determined during initial battery installation are recorded with the battery replacement specifications, FES 95-206-ED-01 and FES 95-206-ED-02.

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The 12 month Frequency for this SR is consistent with IEEE-450 (Ref. 4), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection. The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.4.

The specified limits for connection resistance are discussed in the Bases for SR 3.8.4.2.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.4 and SR 3.8.4.5 (continued)

The Surveillance Frequencies of 12 months is consistent with IEEE-450 (Ref. 4), which recommends cell to cell and terminal connection resistance measurement on a yearly basis.

SR 3.8.4.6

This SR requires that each required battery charger be capable of supplying 180 amps at 125 V for ≥ 8 hours. These requirements are based on the design capacity of the chargers. The chargers are rated at 200 amps; the specified 180 amps provides margin between the charger rating and the test requirement.

The specified Frequency requires each required battery charger to be tested each 18 months. The Surveillance Frequency is acceptable, given the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.7

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 FSAR Chapter 8 (Ref. 2).

The Surveillance Frequency of 18 months is consistent with the recommendations of RG 1.32 (Ref. 6) and RG 1.129 (Ref. 7), which state that the battery service test should be performed during refueling operations, or at some other outage, with intervals between tests not to exceed 18 months.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

The reason for the restriction that the plant be outside of MODES 1, 2, 3, and 4 is that performing the Surveillance requires disconnecting the battery from the DC distribution buses and connecting it to a test load resistor bank. This action makes the battery inoperable and completely unavailable for use.

SR 3.8.4.8

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.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; 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 envelop the duty cycle of the service test. Since the ampere-hours removed by a rated 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 should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

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.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

The acceptance criteria for this Surveillance are consistent with the recommendations of IEEE-450 (Ref. 4) and IEEE-485 (Ref. 3). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 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. 4), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 4).

The reason for the restriction that the plant be outside of MODES 1, 2, 3, and 4 is that performing the Surveillance requires disconnecting the battery from the DC distribution buses and connecting it to a test load resistor bank. This action makes the battery inoperable and completely unavailable for use.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17
2. FSAR, Chapter 8
3. IEEE-485-1983, June 1983
4. IEEE-450-1995
5. Letter; Graham Walker, C&D Charter Power Systems, Inc to John Slinkard, Consumers Power Company, 12 July 1996
6. Regulatory Guide 1.32, February 1977
7. Regulatory Guide 1.129, December 1974

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	A description of the Safety Analyses applicable during MODES 5 and 6 is provided in the Bases for LCO 3.8.2, "AC Sources - Shutdown." The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2).
LCO	This LCO requires those, and only those, DC power sources which supply the DC distribution subsystems required by LCO 3.8.10, to be OPERABLE. Each DC source consists of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling. This ensures the availability of sufficient DC power sources to maintain the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and loss of shutdown cooling).
APPLICABILITY	The DC power sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies provide assurance that equipment and instrumentation is available to: a. Provide coolant inventory makeup, b. Mitigate a fuel handling accident, c. Mitigate shutdown events that can lead to core damage, and d. Monitoring and maintaining the plant in a cold shutdown condition or refueling condition. This LCO is applicable during movement of irradiated fuel assemblies even if the plant is in a condition other than MODE 5 or 6. This LCO provides the necessary ACTIONS if the DC electrical power sources required by this LCO become unavailable during movement of irradiated fuel assemblies. The DC source requirements for MODES 1, 2, 3, and 4 are addressed in LCO 3.8.4, "DC Sources - Operating."

BASES

ACTIONS

A.1

Since the required DC source is only required to support features required by other LCOs, the option to declare those required features with no DC power available to be inoperable, assures that appropriate ACTIONS will be implemented in accordance with the affected LCOs.

A.2.1, A.2.2, A.2.3, and A.2.4

Required Action A.1 may involve undesired and unnecessary administrative efforts, therefore, Required Actions A.2.1 through A.2.4 provide alternate, but sufficiently conservative, actions.

Required Actions A.2.1 through A.2.4 require suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions. The suspension of CORE ALTERATIONS and movement of irradiated fuel assemblies does not preclude actions to place a fuel assembly in a safe location; the suspension of positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SHUTDOWN MARGIN is maintained.

These ACTIONS minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC sources (and to continue this action until restoration is accomplished) in order to provide the necessary DC power to the plant safety systems.

The Completion Time of "immediately" is consistent with the required times for actions requiring prompt attention. The restoration of the required DC power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient control and Preferred AC power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires the SRs from LCO 3.8.4 that are necessary for ensuring the OPERABILITY of the AC sources in MODES 5 and 6.

The SRs from LCO 3.8.4 which are required are those which can be performed without affecting the OPERABILITY or reliability of the required DC source. With only one battery available, loading tests cannot be performed since their performance would render that battery inoperable during the test. This is the case for SRs 3.8.4.7 and 3.8.4.8.

REFERENCES

None

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND	This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries is provided in the Bases for LCO 3.8.4, "DC Sources - Operating."
APPLICABLE SAFETY ANALYSES	A description of the Safety Analyses applicable for MODES 1, 2, 3, and 4 is provided in the Bases for LCO 3.8.1, "AC Sources - Operating"; during MODES 5 and 6, in the Bases for LCO 3.8.2, "AC Sources - Shutdown." Battery cell parameters satisfy Criterion 3 of 10 CFR 50.36(c)(2).
LCO	Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery cell limits are conservatively established, allowing continued DC electrical system function even when Category A and B limits are not met. The requirement to maintain the average temperature of representative cells above 70°F assures that the battery temperature is within the design band. Battery capacity is a function of battery temperature.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated DC power sources. Therefore, they are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussions in the Bases for LCO 3.8.4 and LCO 3.8.5, "DC Sources - Shutdown."

BASES

ACTIONS

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

With one or more cells in one or more batteries not within Category A or B limits but within the Category C limits, the battery is not fully charged but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be declared to be inoperable and continued operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check will provide a quick indication of the status of the remainder of the battery. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells.

Verification that all cells meet the Category C limits (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery will still be capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements may be required to be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A and B limits.

Battery cell parameters must be restored to Category A and B limits within 31 days.

B.1

With the temperature of representative cells below the design temperature, or with one or more battery cells with parameters outside the Category C limits, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding battery must be declared inoperable.

Additionally, if battery cells cannot be restored to meeting Category A or B limits within 31 days, a serious difficulty with the battery is indicated and the battery must be declared to be inoperable.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 1), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

SR 3.8.6.2

This Surveillance verification that the average temperature of representative cells is ≥ 70°F is consistent with a recommendation of IEEE-450 (Ref. 1), which states that the temperature of electrolytes in representative cells should be determined on a quarterly basis. The monthly frequency specified is a feature of the initial Palisades license, and is the same as those other pilot cell tests specified in SR 3.8.6.1.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer recommendations.

SR 3.8.6.3

The quarterly inspection of specific gravity and voltage is consistent with the recommendations of IEEE-450 (Ref. 1).

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. Each category is discussed below.

Category A defines the fully charged parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage and specific gravity approximate the state of charge of the entire battery.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category A and B limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 1), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote (a) to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A and B limit specified for float voltage is ≥ 2.13 V per cell. This value is based on a recommendation of IEEE-450, which states that prolonged operation of cells < 2.13 V can reduce their life expectancy.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.205. This value is six points (0.006) below the average baseline specific gravity for fully charged cells when the battery was installed and is characteristic of a charged cell with adequate capacity.

The Category B limit specified for specific gravity for each connected cell is ≥ 1.200. Category B also requires that the average of all cells be ≥ 1.205 (0.006 below the baseline average of all cells). This allows some cells to be slightly lower than the nominal requirement as long as others are sufficiently higher so as to maintain the average above the nominal full charged value. According to IEEE-450, specific gravity readings are based on a temperature of 77°F (25°C).

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists and the battery must be declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limit for float voltage is based on IEEE-450, which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C specific gravity limit that each connected cell must be no less than 0.020 below the average of all connected cells and that average be ≥ 1.195 is based on manufacturer recommendations (0.020 below the manufacturer recommended fully charged, nominal specific gravity) (Ref. 2). This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

Footnote (a) allows for the normally observed level increase which occurs during sustained battery charging. Footnotes (b) and (c) to Table 3.8.6-1 are applicable to Category A, B, and C specific gravity. Footnote (b) to Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current is < 2 amps on float charge. This current provides, in general, an indication of overall battery condition.

Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity readings. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 1).

REFERENCES

1. IEEE-450-1995

2. C & D Standby Battery Installation and Operation Instructions

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters (ED-06, ED-07, ED-08, and ED-09) are the normal source of power for the Preferred AC buses. The function of the inverter is to provide continuous AC electrical power to the Preferred AC buses, even in the event of an interruption to the normal AC power distribution system. A Preferred AC bus can be powered from the AC power distribution system via the Bypass Regulator if its associated inverter is out of service. An interlock prevents supplying more than one Preferred AC bus from the bypass regulator at any time. The station battery provides an uninterruptable power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Features (ESF).

APPLICABLE SAFETY ANALYSES

A description of the Safety Analyses applicable in MODES 1, 2, 3, and 4 is provided in the Bases for LCO 3.8.1, "AC Sources - Operating."

Inverters are part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The inverters ensure the availability of Preferred AC power for the instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA.

Maintaining the inverters OPERABLE ensures that the redundancy incorporated into the RPS and ESF instrumentation and controls is maintained. The four inverters ensure an uninterruptable supply of AC electrical power to the Preferred AC buses even if the 2400 V safety related buses are de-energized.

An inverter is considered inoperable if it is not powering the associated Preferred AC bus, or if its output voltage or frequency is not within tolerances.

BASES

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that redundant sources of Preferred AC power for instrumentation and control are available to support engineered safeguards equipment in the event of an accident or transient and for power operation, plant heatups and cooldowns, and shutdown operation.

Inverter requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are addressed in LCO 3.8.8, "Inverters - Shutdown."

ACTIONS

A.1

With an inverter inoperable, its associated Preferred AC bus becomes inoperable until it is manually re-energized from the bypass regulator. An inoperable Preferred AC Bus is addressed in LCO 3.8.9.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant 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.

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to an operating condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly and energizing the Preferred AC buses. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation of the RPS and ESF connected to the Preferred AC buses. The 7 day Frequency takes into account indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

None

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	A description of the Safety Analyses applicable during MODES 5 and 6 is provided in the Bases for LCO 3.8.2, "AC Sources - Shutdown." Inverters are part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2).
LCO	This LCO requires those, and only those, inverters necessary to support the Preferred AC buses required by LCO 3.8.10, "Distribution Systems - Shutdown," to be OPERABLE. This ensures the availability of sufficient Preferred AC electrical power to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and loss of shutdown cooling). An inverter is considered inoperable if it is not powering the associated Preferred AC bus, or if its voltage or frequency is not within tolerances.
APPLICABILITY	The inverters required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies provide assurance that equipment and instrumentation is available to: a. Provide coolant inventory makeup, b. Mitigate a fuel handling accident, c. Mitigate shutdown events that can lead to core damage, and d. Monitoring and maintaining the plant in a cold shutdown condition or refueling condition.

BASES

APPLICABILITY (continued)

This LCO is applicable during movement of irradiated fuel assemblies even if the plant is in a condition other than MODE 5 or 6. This LCO provides the necessary ACTIONS if the inverters required by this LCO become unavailable during movement of irradiated fuel assemblies.

Inverter requirements for MODES 1, 2, 3, and 4 are addressed in LCO 3.8.7.

ACTIONS

A.1

An inverter would be considered inoperable if it were not available to supply its associated Preferred AC bus. Since the inverter and its associated Preferred AC Bus is only required to support features required by other LCOs, the option to declare those required features without inverter supplied Preferred AC power available to be inoperable, assures that appropriate ACTIONS will be implemented in accordance with the affected LCOs.

A.2.1, A.2.2, A.2.3, and A.2.4

Required Action A.1 may involve undesired and unnecessary administrative efforts, therefore, Required Actions A.2.1 through A.2.4 provide alternate, but sufficiently conservative, actions.

Required Actions A.2.1 through A.2.4 require suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions. The suspension of CORE ALTERATIONS and movement of irradiated fuel assemblies does not preclude actions to place a fuel assembly in a safe location; the suspension of positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SHUTDOWN MARGIN is maintained.

These ACTIONS minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters (and to continue this action until restoration is accomplished) in order to provide the required inverter supplied Preferred AC power to the plant instrument and control systems.

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

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 during which the plant safety systems may be without inverter supplied Preferred AC power.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

A description of the basis for this SR is provided in the Bases for SR 3.8.7.1.

REFERENCES

None

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems - Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and Preferred AC bus electrical power distribution systems are divided into two redundant and independent electrical power distribution trains. Each electrical power distribution train is made up of several subsystems which include the safety related buses, load centers, motor control centers, and distribution panels shown in Table B 3.8.9-1.

The Class 1E 2400 V safety related buses, Bus 1C and Bus 1D, are normally powered from offsite, but can be powered from the DGs, as explained in the Background section of the Bases for LCO 3.8.1, "AC Sources - Operating." Each 2400 V safety related bus supplies one train of the Class 1E 480 V distribution system.

The 120 V Preferred AC buses are normally powered from the inverters. The alternate power supply for the buses is a constant voltage transformer, called the Bypass Regulator. Use of the Bypass regulator is governed by LCO 3.8.7, "Inverters - Operating." The bypass regulator is powered from the non-Class 1E instrument AC bus, Y-01. The Instrument AC bus is normally powered through an automatic bus transfer switch, an instrument AC transformer, and isolation fuses. Its normal power source is MCC-1. Loss of power to MCC-1 will cause automatic transfer of the Instrument AC bus to MCC-2.

There are two independent 125 V DC electrical power distribution subsystems.

APPLICABLE SAFETY ANALYSES

A description of the Safety Analyses applicable in MODES 1, 2, 3, and 4 is provided in the Bases for LCO 3.8.1.

The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

The AC, DC, and Preferred AC bus electrical power distribution subsystems are required to be OPERABLE. The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and Preferred AC bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA.

BASES

LCO (continued)

Maintaining both trains of AC, DC, and Preferred AC bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the plant design is not defeated. Therefore, a single failure within any electrical power distribution subsystem will not prevent safe shutdown of the reactor.

OPERABLE electrical power distribution subsystems require the buses, load centers, motor control centers, and distribution panels listed in Table B 3.8.9-1 to be energized to their proper voltages. In addition, tie breakers between redundant safety related AC power distribution subsystems must be open when a 2400 V source is OPERABLE for each train. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem. If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 2400 V buses from being powered from the same offsite circuit or preclude cross connecting Class 1E 480 V subsystems when 2400 V power is available for only one train.

This LCO does not address the power source for the Preferred AC buses. The Preferred AC buses are normally powered from the associated inverter. An alternate source, the Bypass Regulator, is available to supply one Preferred bus at a time, to allow maintenance on an inverter. The proper alignment of the inverter output breakers is addressed under the inverter LCOs. Therefore a Preferred AC Bus may be considered OPERABLE when powered from either the associated inverter or the Bypass Regulator as long as the voltage and frequency of the supply is correct.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that AC, DC, and Preferred AC power is available to the redundant trains and channels of safeguards equipment, instrumentation and controls required to support engineered safeguards equipment in the event of an accident or transient.

Electrical power distribution subsystem requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are addressed in LCO 3.8.10, "Distribution Systems - Shutdown."

BASES

ACTIONS

A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels, except Preferred AC buses, in one train inoperable, the redundant AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because an additional failure in the power distribution systems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combinations of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 16 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

B.1

With one Preferred AC bus inoperable, the remaining OPERABLE Preferred AC buses are capable of supporting the minimum safety functions necessary to shut down the plant 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 Preferred AC bus must be restored to OPERABLE status within 8 hours by powering it from the associated inverter or from the Bypass Regulator.

BASES

ACTIONS

B.1 (continued)

This 8 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate Preferred AC power and is a feature of the original Palisades licensing basis.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single continuous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 16 hours, since initial failure of the LCO, to restore the Preferred AC distribution system. At this time, a DC bus could again become inoperable, and Preferred AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With one or more DC bus in one train inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 8 hours by powering the bus from the associated battery or charger.

This 8 hour limit is more conservative than Completion Times allowed for the vast majority of components which would be without power and is a feature of the original Palisades licensing basis.

BASES

ACTIONS

C.1 (continued)

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single continuous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 16 hours, since initial failure of the LCO, to restore the Preferred DC distribution system. At this time, a AC bus could again become inoperable, and Preferred AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to an operating condition 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.

E.1

Condition E corresponds to a degradation in the electrical distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This surveillance verifies that the required AC, DC, and Preferred AC bus electrical power distribution subsystems 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.

For those buses which have undervoltage alarms in the control room, correct voltage may be verified by the absence of an undervoltage alarm.

For those buses which have only one possible power source and have undervoltage alarms in the control room, correct breaker alignment may be verified by the absence of an undervoltage alarm.

A Preferred AC Bus may be considered correctly aligned when powered from either the associated inverter or from the bypass regulator. A mechanical interlock prevents connecting two or more Preferred AC Buses to the Bypass Regulator. LCO 3.8.7 and SR 3.8.7.1 address the condition of supplying a Preferred AC Bus from the bypass regulator.

The 7 day Frequency takes into account the redundant capability of the AC, DC, and Preferred AC bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES None

TABLE B 3.8.9-1 (page 1 of 1)
Required Electrical Distribution Trains

TYPE	VOLTAGE	LEFT TRAIN	RIGHT TRAIN
AC Power Distribution Subsystems	2400	Bus 1C	Bus 1D
	480	Bus 11	Bus 12
	480	Bus 19	Bus 20
	480	MCC 1	MCC 2
	480	MCC 7	MCC 8
	480	MCC 21	MCC 22
	480	MCC 23	MCC 24
	480	MCC 25	MCC 26
DC Power Distribution Subsystems	125	Bus D10-L	Bus D20-L
	125	Bus D10-R	Bus D20-R
	125	Pnl D11A	Pnl D21A
	125	Pnl D11-1	Pnl D21-1
	125	Pnl D11-2	Pnl D21-2
Preferred AC Subsystems	120	Bus Y-10	Bus Y-20
	120	Bus Y-30	Bus Y-40

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of the AC, DC, and Preferred AC bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

A description of the Safety Analyses applicable during MODES 5 and 6 is provided in the Bases for LCO 3.8.2, "AC Sources - Shutdown."

The distribution system satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO requires those, and only those, AC, DC, and Preferred AC distribution subsystems to be OPERABLE which are necessary to support equipment required by other LCOs.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that equipment and instrumentation is available to:

a. Provide coolant inventory makeup,

b. Mitigate a fuel handling accident,

c. Mitigate shutdown events that can lead to core damage, and

d. Monitoring and maintaining the plant in a cold shutdown condition and refueling condition.

This LCO is applicable during movement of irradiated fuel assemblies even if the plant is in a condition other than MODE 5 or 6. This LCO provides the necessary ACTIONS if the electrical power distribution subsystems required by this LCO become unavailable during movement of irradiated fuel assemblies.

BASES

APPLICABILITY (continued)

The electrical power distribution subsystem requirements for MODES 1, 2, 3, and 4 are addressed in LCO 3.8.9, "Distribution Systems - Operating."

ACTIONS

A.1

Since the distribution systems are only required to support features required by other LCOs, the option to declare those affected required features to be inoperable assures that appropriate ACTIONS will be implemented in accordance with the affected LCOs.

A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Required Action A.1 may involve undesired and unnecessary administrative efforts, therefore, Required Actions A.2.1 through A.2.5 provide alternate, but sufficiently conservative, actions.

Required Actions A.2.1, A.2.2, A.2.3, and A.2.5 require suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions, and declaration that affected shutdown cooling trains are inoperable. The suspension of CORE ALTERATIONS and movement of irradiated fuel assemblies does not preclude actions to place a fuel assembly in a safe location; the suspension of positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SHUTDOWN MARGIN is maintained.

These ACTIONS minimize the probability or the occurrence of postulated events. It is further required (Required Action A.2.4) to immediately initiate action to restore the required distribution subsystems (and to continue this action until restoration is accomplished) in order to provide the necessary electrical power to the plant safety systems.

The Completion Time of "immediately" is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

A description of the basis for this SR is provided in the Bases for SR 3.8.9.1.

REFERENCES

None

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Primary Coolant System (PCS), and refueling cavity during refueling ensures that the reactor remains subcritical during MODE 6. The refueling operations 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 defined in Section 1.1, "Definitions." Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures. During evolutions where plant procedures allow manipulation of control rods or where conditions could result in inadvertent control rod withdrawal, such as reactor vessel head removal, the boron concentration must be sufficient to assure that k_{eff} will remain ≤ 0.95 without taking credit for the negative reactivity provided by the control rods (i.e., assuming all rods fully withdrawn). During evolutions where the control rods are inserted, plant procedures do not allow manipulation of control rods, and conditions do not exist that could result in inadvertent rod withdrawal, such as MODE 6 operations with the Upper Guide Structure in place (other than during head removal). Therefore, credit may be taken for the negative reactivity provided by the control rods when determining the boron concentration necessary to assure that k_{eff} will remain ≤ 0.95.

The Palisades Nuclear Plant design criteria 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) System is capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

BASES

BACKGROUND (continued)

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the PCS is cooled and depressurized the vessel head is unbolted and the head is removed. The refueling cavity is then flooded with borated water from the safety injection refueling water tank into the open reactor vessel by gravity feeding or by the use of the spent fuel cooling, safety injection pumps, or charging pumps.

The pumping action of the SDC System in the PCS and the natural circulation due to thermal driving head in the reactor vessel mix the added concentrated boric acid with the water in the refueling cavity. The SDC System is in operation during refueling (see LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation - Low Water Level") to provide forced circulation in the PCS and to assist in maintaining the REFUELING BORON CONCENTRATION in the PCS, and the refueling cavity.

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident analysis and is conservative for MODE 6. The REFUELING BORON CONCENTRATION limit is based on the core reactivity and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that demonstrate the correct fuel loading plan (including full core mapping) ensure the k_{eff} of the core will remain $\leq$ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling 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). A detailed discussion of this event is provided in B 3.1.1, "SHUTDOWN MARGIN."

Boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2).

BASES

LCO

The LCO requires that a minimum boron concentration be maintained in the PCS, and refueling cavity while in MODE 6. The boron concentration limit specified ensures a core k_{eff} of $\leq$ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality.

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)," ensure that an adequate amount of negative reactivity is available to shut down the reactor and to maintain it subcritical.

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 plant in compliance with the LCO. If the boron concentration of any coolant volume in the PCS 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, or normal cooldown of the coolant volume for the purpose of system temperature control.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, there is no unique design basis event that 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 plant conditions.

BASES

ACTIONS

A.3 (continued)

Once boration is initiated, it 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 the coolant boron concentration in the PCS and the refueling cavity is within the limit. The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

A minimum Frequency of once every 72 hours is therefore a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

REFERENCES

1. FSAR, Section 5.1
2. FSAR, Section 14.3

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND

The source range channels (NI-01/03 and NI-02/04) are used during refueling operations to monitor the core reactivity condition. The installed source range channels are part of the Nuclear Instrumentation System. These detectors are located external to the reactor vessel and detect neutrons leaking from the core. The use of portable detectors is permitted, provided the LCO requirements are met.

The installed source range channels utilize fission detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers five decades of neutron flux (1E+5 cps). The detectors provide continuous visual and audible indication in the control room to alert operators to a possible dilution accident. The Nuclear Instrumentation System is designed in accordance with the criteria presented in Reference 1.

If used, portable detectors should be functionally equivalent to the installed source range channels.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range channels are required to provide a signal to alert the operator to unexpected changes in core reactivity such as by a boron dilution accident or an improperly loaded fuel assembly. The safety analysis of the uncontrolled boron dilution accident is described in Reference 2. The analysis of the uncontrolled boron dilution accident shows that normally available SHUTDOWN MARGIN would be reduced, but there is sufficient time for the operator to take corrective actions.

Nuclear Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO requires two source range channels OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. To be OPERABLE, each channel must provide visual indication and at least one of the two channels must provide an audible count rate function in the control room. Therefore, with no audible count rate function from at least one channel, both source range channels would be inoperable.

BASES

APPLICABILITY

In MODE 6, the source range channels must be OPERABLE to detect changes in core reactivity. There is no other direct means available to check core reactivity levels.

In MODES 2, 3, 4, and 5 with no more than one control rod capable of withdrawal, the installed source range channels are required to be OPERABLE by LCO 3.3.9, "Neutron Flux Monitoring Channels." In MODE 1, one source range channel is required by LCO 3.3.8, "Alternate Shutdown System."

ACTIONS

A.1 and A.2

With only one source range channel OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position or normal cooldown of the coolant volume for the purpose of system temperature control.

B.1

With no source range channel OPERABLE, action to restore a channel to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until one source range channel is restored to OPERABLE status.

B.2

With no source range channel OPERABLE, there is no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range channel are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to verify that the required boron concentration exists.

BASES

ACTIONS

B.2 (continued)

The Completion Time of once per 12 hours is sufficient to obtain and analyze a primary coolant and refueling cavity sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this period.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions, but does not require the two source range channels to have the same reading. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.9.

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION every 18 months. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed on the 18 month Frequency.

REFERENCES

1. FSAR, Section 7.6

2. FSAR, Section 14.3

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment, a release of fission product radioactivity within the containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are filtered, closed or capable of being closed. Since there is no potential for containment pressurization, the 10 CFR 50, Appendix J leakage criteria and tests are not required. In MODE 5, no accidents are assumed which will result in a release of radioactive material to the containment atmosphere. Therefore, no requirements are stipulated for containment penetrations in MODE 5.

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 well within the requirements of 10 CFR 100. Additionally, the containment structure provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment with the equipment hatch closed, the hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced.

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment with the equipment hatch removed, the OPERABILITY requirements of the Fuel Handling Area Ventilation System must be met. These OPERABILITY requirements are provided in LCO 3.7.12, "Fuel Handling Area Ventilation System."

BASES

BACKGROUND (continued)

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed. An exception, however, is provided for the personnel air lock. It is acceptable to have both doors of the personnel air lock opened simultaneously provided the equipment hatch is opened.

The requirements on containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling.

The Containment Purge and Vent System includes a 12 inch purge penetration and two 8 inch exhaust penetrations. During MODES 1, 2, 3, and 4, the valves in the purge and vent penetrations are secured in the closed position and venting the containment is accomplished using the Clean Waste Receiving Tank (CWRT) vent line. The two valves in the CWRT vent line penetration are closed automatically by a Containment High Radiation signal. Neither the Containment Purge and Vent System, nor the CWRT vent line is subject to a Specification in MODE 5.

In MODE 6, large air exchanges are necessary to conduct refueling operations. The Purge and Vent System is used for this purpose. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment with either the Containment Purge and Vent System in operation, or the CWRT aligned for containment venting, the associated isolation valves must be capable of being closed by an OPERABLE channel of radiation instrumentation required by LCO 3.3.6, "Refueling Containment High Radiation Instrumentation."

BASES

BACKGROUND (continued)

Other containment penetrations that provide direct access from containment atmosphere to outside atmosphere that are not capable of being closed by an OPERABLE Refueling Containment High Radiation signal must be isolated on at least one side. Containment penetrations "that provide direct access from containment atmosphere to outside atmosphere" are those which would allow passage of air containing radioactive particulates to migrate from inside the containment to the atmosphere outside the containment even though no measurable differential pressure existed. Specifically, they do not include penetrations which are filtered, or penetrations whose piping is filled with liquid. Isolation may be achieved by a manual or automatic isolation valve, blind flange, or equivalent. Equivalent isolation methods, authorized under the provisions of 10 CFR 50.59, may include use of a material that can provide a temporary, atmospheric pressure ventilation barrier for the other containment penetrations during fuel movements.

APPLICABLE SAFETY ANALYSES

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. 1). The requirements of LCO 3.9.6, "Refueling Cavity Water Level," (and the minimum decay time of 48 hours required by the Operating Requirements Manual) prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are less than the guideline values specified in 10 CFR 100.

Containment penetration isolation is not required by the fuel handling accident to maintain offsite doses within the guidelines of 10 CFR 100, but operating experience indicates that containment isolation provides significant reduction of the resulting offsite doses. Therefore, the Containment Penetrations satisfy the requirements of Criterion 4 of 10 CFR 50.36(c)(2).

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 the equipment hatch, air locks and any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment penetrations.

BASES

LCO (continued)

For the OPERABLE containment penetrations, this LCO ensures that these penetrations are isolable by the Refueling Containment High Radiation instrumentation. The OPERABILITY requirements for this LCO do not assume a specific closure time for the valves in these penetrations since the accident analysis makes no specific assumptions about containment closure time after a fuel handling accident.

LCO 3.9.3.a is modified by a Note which allows the equipment hatch to be opened if the Fuel Handling Area Ventilation System is in compliance with LCO 3.7.12. LCO 3.9.3.b is modified by a Note which allows both doors of the personnel air lock to be simultaneously opened provided the equipment hatch is opened. In the event of a fuel handling accident inside containment with both doors in the personnel air lock open and the equipment hatch open, the Fuel Handling Area Ventilation System would be available to filter the fission products in the containment atmosphere prior to their being released to the environment and thereby significantly reducing the offsite dose.

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, "Containment."

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

With the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere not in the required status, including the Refueling Containment High Radiation instrumentation not capable of automatic actuation when the purge and exhaust valves are open, the plant must be placed in a condition in which containment closure is not needed.

BASES

ACTIONS

A.1 and A.2 (continued)

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.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the valves in unisolated penetrations which provide a direct path from the containment atmosphere to the outside atmosphere 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 each valve is capable of being closed by an OPERABLE Refueling Containment High Radiation signal.

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. As such, this Surveillance helps ensure that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in an excessive release of fission product radioactivity to the environment.

SR 3.9.3.2

This Surveillance demonstrates that each automatic isolation valve providing direct access from the containment atmosphere to the outside atmosphere valve actuates to its isolation position on an actual or simulated high radiation signal.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1 (continued)

The SR is modified by a Note which requires only the valves in unisolated penetrations to be tested. The 18 month Frequency maintains consistency with other similar ESFAS instrumentation and valve testing requirements. LCO 3.3.6, "Refueling Containment High Radiation Instrumentation," requires a CHANNEL CHECK every 7 days, a CHANNEL FUNCTIONAL TEST every 31 days and a CHANNEL CALIBRATION every 18 months to ensure the channel OPERABILITY during refueling operations. These surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

REFERENCES

1. FSAR, Section 14.19

B 3.9 REFUELING OPERATIONS

B 3.9.4 Shutdown Cooling (SDC) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purposes of the SDC System in MODE 6 are to remove decay heat and sensible heat from the Primary Coolant System (PCS), as required by the Palisade Nuclear Plant design, to provide mixing of borated coolant, to provide sufficient coolant circulation to minimize the effects of a boron dilution accident, and to prevent boron stratification (Ref. 1). Heat is removed from the PCS by circulating primary coolant through the SDC heat exchanger(s), where the heat is transferred to the Component Cooling Water System via the SDC heat exchanger(s). The coolant is then returned to the PCS via the PCS cold leg(s). Operation of the SDC 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 primary coolant through the SDC heat exchanger(s) and bypassing the heat exchanger(s). Mixing of the primary coolant is maintained by this continuous circulation of primary coolant through the SDC System.

APPLICABLE SAFETY ANALYSES

If the primary coolant temperature is not maintained below 200°F, boiling of the primary coolant could result. This could lead to inadequate cooling of the reactor fuel due to the resulting loss of coolant in the reactor vessel. Additionally, boiling of the primary coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity, and because of the possible addition of water to the reactor vessel with a lower boron concentration than is required to keep the reactor subcritical.

The loss of primary coolant and the reduction of boron concentration in the primary coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the SDC System is required to be in operation in MODE 6, with the refueling cavity water level greater than or equal to the 647 ft elevation, to prevent this challenge. The LCO allows the removal of an SDC train from operation for short durations under the condition that the boron concentration is not diluted.

BASES

APPLICABLE SAFETY ANALYSES (continued)

This conditional allowance does not result in a challenge to the fission product barrier.

SDC and Coolant Circulation — High Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2).

LCO

Only one SDC train is required for decay heat removal in MODE 6, with the refueling cavity water level greater than or equal to the 647 ft elevation. Only one SDC train is required because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one SDC train must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of a criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE SDC train consists of an SDC pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the PCS temperature. The flow path starts in one of the PCS hot legs and is returned to at least one PCS cold leg.

The LCO is modified by two Notes. Note 1 allows the required operating SDC train to not be in operation for up to 1 hour in each 8 hour period, provided no operations are permitted that would cause a reduction of the PCS boron concentration. Boron concentration reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles, and PCS to SDC isolation valve testing.

During this 1 hour period, decay heat is removed by natural circulation to the large mass of water in the refueling cavity. Note 2 allows the required SDC train to be made inoperable for ≤ 2 hours per 8 hour period for testing and maintenance provided one SDC train in operation providing flow through the reactor core, and the core outlet temperature is ≤ 200°F. The purpose of this Note is to allow the heat flow path from the SDC heat exchanger to be temporarily interrupted for maintenance or testing on the Component Cooling Water or Service Water Systems.

BASES

LCO (continued)

During this 2 hour period, the core outlet temperature must be maintained ≤ 200°F. Requiring one SDC train to be in operation continues to ensures adequate mixing of the borated coolant.

APPLICABILITY

One SDC train must be OPERABLE and in operation in MODE 6, with the refueling cavity water level greater than or equal to 647 ft elevation, to provide decay heat removal. The 647 ft elevation was selected because it corresponds to the elevation requirement established for fuel movement in LCO 3.9.6, "Refueling Cavity Water Level." Requirements for the SDC System in other MODES are covered by LCOs in Section 3.4, "Primary Coolant System (PCS)." SDC train requirements in MODE 6, with the refueling cavity water level less than the 647 ft elevation are located in LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation — Low Water Level."

ACTIONS

SDC train requirements are met by having one SDC train OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If one required SDC train is inoperable or not in operation, actions shall be immediately initiated and continued until the SDC train is restored to OPERABLE status and to operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

A.2

If SDC train requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations can occur through the addition of water with a lower boron concentration than that contained in the PCS. Therefore, actions that reduce boron concentration shall be suspended immediately.

BASES

ACTIONS (continued)

A.3

If SDC train requirements are not met, actions shall be taken immediately to suspend loading irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural circulation to the heat sink provided by the water above the core. A minimum refueling cavity water level equivalent to the 647 ft elevation provides an adequate available heat sink. Suspending any operation that would increase the decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.4

If SDC train requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed to prevent fission products, if released by a loss of decay heat removal event, from escaping to the environment. The 4 hour Completion Time is based on the low probability of the coolant boiling in that time and allows time for fixing most SDC problems.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the SDC train is in operation and circulating primary coolant. The flow rate is sufficient to provide decay heat removal capability and to prevent thermal and boron stratification in the core. The 1000 gpm flow rate has been determined by operating experience rather than analysis. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the SDC System.

REFERENCES

1. FSAR, Sections 6.1 and 14.3

B 3.9 REFUELING OPERATIONS

B 3.9.5 Shutdown Cooling (SDC) and Coolant Circulation - Low Water Level

BASES

BACKGROUND

The purposes of the SDC System in MODE 6 are to remove decay heat and sensible heat from the Primary Coolant System (PCS), as required by the Palisades Nuclear Plant design, to provide mixing of borated coolant, to provide sufficient coolant circulation to minimize the effects of a boron dilution accident, and to prevent boron stratification (Ref. 1). Heat is removed from the PCS by circulating primary coolant through the SDC heat exchanger(s), where the heat is transferred to the Component Cooling Water System via the SDC heat exchanger(s). The coolant is then returned to the PCS via the PCS cold leg(s). Operation of the SDC 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 primary coolant through the SDC heat exchanger(s) and bypassing the heat exchanger(s). Mixing of the primary coolant is maintained by this continuous circulation of reactor primary through the SDC System.

APPLICABLE SAFETY ANALYSES

If the primary coolant temperature is not maintained below 200°F, boiling of the primary coolant could result. This could lead to inadequate cooling of the reactor fuel due to the resulting loss of coolant in the reactor vessel. Additionally, boiling of the primary coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity, and because of the possible addition of water to the reactor vessel with a lower boron concentration than is required to keep the reactor subcritical.

The loss of primary coolant and the reduction of boron concentration in the primary coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the SDC System are required to be OPERABLE, and one train is required to be in operation in MODE 6, with the refueling cavity water level less than the 647 ft elevation to prevent this challenge.

SDC and Coolant Circulation — Low Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2).

BASES

LCO

In MODE 6, with the refueling cavity water level less than the 647 ft elevation, both SDC trains must be OPERABLE. Additionally, one train of the SDC System must be in operation in order to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of a criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE SDC train consists of an SDC pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the PCS temperature. The flow path starts in one of the PCS hot legs and is returned to the PCS cold legs.

Both SDC pumps may be aligned to the safety injection refueling water tank to support filling the refueling cavity or for performance of required testing.

APPLICABILITY

Two SDC trains are required to be OPERABLE, and one SDC train must be in operation in MODE 6, with the refueling cavity water level less than the 647 ft elevation to provide decay heat removal. Requirements for the SDC System in other MODES are covered by LCOs in Section 3.4, "Primary Coolant System." MODE 6 requirements, with the refueling cavity water level greater than or equal to the 647 ft elevation are covered in LCO 3.9.4, "Shutdown Cooling and Coolant Circulation - High Water Level."

ACTIONS

A.1 and A.2

If one SDC train is inoperable, action shall be immediately initiated and continued until the SDC train is restored to OPERABLE status and to operation, or until a water level of greater than or equal to the 647 ft elevation is established. When the water level is established at the 647 ft elevation or greater, the Applicability will change to that of LCO 3.9.4, "Shutdown Cooling and Coolant Circulation - High Water Level," and only one SDC train is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

BASES

ACTIONS (continued)

B.1

If no SDC train is in operation or no SDC trains are OPERABLE, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations can occur by the addition of water with lower boron concentration than that contained in the PCS. Therefore, actions that reduce boron concentration shall be suspended immediately.

B.2

If no SDC train is in operation or no SDC trains are OPERABLE, action shall be initiated immediately and continued without interruption to restore one SDC train to OPERABLE status and operation. Since the plant is in Conditions A and B concurrently, the restoration of two OPERABLE SDC trains and one operating SDC train should be accomplished expeditiously.

B.3

If no SDC train is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed Immediately. With the SDC train 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.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that one SDC train is operating and circulating primary coolant. The flow rate is sufficient to provide decay heat removal capability and to prevent thermal and boron stratification in the core.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 (continued)

In addition, during operation of the SDC train with the water level in the vicinity of the reactor vessel nozzles, the SDC train flow rate determination must also consider the SDC pump suction requirements. The 1000 gpm flow rate has been determined by operating experience rather than analysis. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator to monitor the SDC System in the control room.

SR 3.9.5.2

Verification that the required pump is OPERABLE ensures that an additional SDC pump can be placed in operation, if needed, to maintain decay heat removal and primary coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR, Sections 6.1 and 14.3

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Cavity Water Level

BASES

BACKGROUND

The performance of CORE ALTERATION or the movement of irradiated fuel assemblies within containment requires a minimum water level greater than or equal to the 647 ft elevation. During refueling this maintains sufficient water level in the 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 less than the guidelines of 10 CFR 100.

APPLICABLE SAFETY ANALYSES

During core alterations and during movement of irradiated fuel assemblies, the water level in the refueling cavity is an initial condition design parameter in the analysis of the fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 ft (Regulatory Position C.1.c of Ref. 1), which is approximate to an elevation of 647 ft, allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99% 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 12% of the total fuel rod iodine 131 inventory (Ref. 2).

The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level greater than or equal to the 647 ft elevation (and the minimum decay time of 48 hours required by the Operating Requirements Manual) prior to fuel handling, the analysis demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within the guidelines of 10 CFR 100.

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

A minimum refueling cavity water level greater than or equal to the 647 ft elevation is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are less than the guideline of 10 CFR 100.

BASES

APPLICABILITY

LCO 3.9.6 is applicable during CORE ALTERATIONS, and when moving fuel assemblies in the presence of irradiated fuel assemblies in 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 is 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 3.7.14, "Spent Fuel Pool Water Level."

ACTIONS

A.1 and A.2

With a water level below the 647 ft elevation, all operations involving CORE ALTERATIONS or movement of irradiated fuel assemblies shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level corresponding to the 647 ft elevation ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required elevation limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972

2. FSAR, Section 14.19