Technical Specification 5.5.14

Palo Verde Nuclear
Generating Station

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102-05739-TNW/CJS
September 04, 2007

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2 and 3
Docket Nos. STN 50-528/529/530
Technical Specifications Bases Revisions 42, 43, 44 and 45 Updates

Pursuant to PVNGS Technical Specification (TS) 5.5.14, "Technical Specifications Bases Control Program," Arizona Public Service Company (APS) is submitting changes to the TS Bases incorporated into Revisions 42, 43, 44 and 45, implemented on February 21, March 14, June 20, and August 29, 2007 respectively. Each revision's insertion instructions and replacement pages are provided in the Enclosures.

No commitments are being made to the NRC by this letter. Should you have any questions, please contact Glenn Michael at (623) 393-5750.

Sincerely,

TNW/GAM/CJS/gat

A001
NRR

Enclosure 1 - PVNGS Technical Specification Bases Revision 42 Insertion Instructions and Replacement Pages

Enclosure 2 - PVNGS Technical Specification Bases Revision 43 Insertion Instructions and Replacement Pages

Enclosure 3 - PVNGS Technical Specification Bases Revision 44 Insertion Instructions and Replacement Pages

Enclosure 4 - PVNGS Technical Specification Bases Revision 45 Insertion Instructions and Replacement Pages

cc:	B. S. Mallett	NRC Region IV Regional Administrator (enclosures)
	M. T. Markley	NRC NRR Project Manager (enclosures)
	G. G. Warnick	NRC Senior Resident Inspector for PVNGS (enclosures)

ENCLOSURE 1

PVNGS
Technical Specification Bases
Revision 42

Insertion Instructions and
Replacement Pages

Insertion Instructions for the Technical Specifications Bases Revision 42

REMOVE PAGES	INSERT PAGES
Cover page	Cover page
List of Effective Pages 1/2 through 7/8	List of Effective Pages 1/2 through 7/8
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B 3.6.5-2	1	B 3.7.6-3	28
B 3.6.5-3	0	B 3.7.6-4	0
B 3.6.5-4	0	B 3.7.7-1	0
B 3.6.6-1	0	B 3.7.7-2	1
B 3.6.6-2	0	B 3.7.7-3	1
B 3.6.6-3	38	B 3.7.7-4	1
B 3.6.6-4	7	B 3.7.7-5	1
B 3.6.6-5	1	B 3.7.8-1	1
B 3.6.6-6	0	B 3.7.8-2	1
B 3.6.6-7	1	B 3.7.8-3	1
B 3.6.6-8	1	B 3.7.8-4	1
B 3.6.6-9	0	B 3.7.9-1	0
B 3.6.7-1	0	B 3.7.9-2	1
B 3.6.7-2	0	B 3.7.9-3	0
B 3.6.7-3	42	B 3.7.10-1	10
B 3.6.7-4	0	B 3.7.10-2	1
B 3.6.7-5	0	B 3.7.10-3	1
B 3.7.1-1	28	B 3.7.10-4	1
B 3.7.1-2	34	B 3.7.11-1	0
B 3.7.1-3	34	B 3.7.11-2	0
B 3.7.1-4	34	B 3.7.11-3	21
B 3.7.1-5	34	B 3.7.11-4	10
B 3.7.1-6	28 Corrected	B 3.7.11-5	10
B 3.7.2-1	40	B 3.7.11-6	10
B 3.7.2-2	42	B 3.7.12-1	1
B 3.7.2-3	40	B 3.7.12-2	21
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B 3.7.2-6	40	B 3.7.13-1	0
B 3.7.2-7	40	B 3.7.13-2	0
B 3.7.2-8	40	B 3.7.13-3	0
B 3.7.2-9	40	B 3.7.13-4	0
B 3.7.3-1	1	B 3.7.13-5	0
B 3.7.3-2	1	B 3.7.14-1	0
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B 3.7.17-4	3	B 3.8.3-1	0
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B 3.8.1-2	2	B 3.8.3-5	34
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B 3.8.1-8	42	B 3.8.4-1	0
B 3.8.1-9	42	B 3.8.4-2	37
B 3.8.1-10	2	B 3.8.4-3	0
B 3.8.1-11	2	B 3.8.4-4	2
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B 3.8.1-23	41	B 3.8.5-5	2
B 3.8.1-24	41	B 3.8.5-6	2
B 3.8.1-25	41	B 3.8.6-1	0
B 3.8.1-26	41	B 3.8.6-2	0
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B 3.8.1-31	41	B 3.8.6-7	0
B 3.8.1-32	41	B 3.8.7-1	0
B 3.8.1-33	41	B 3.8.7-2	0
B 3.8.1-34	41	B 3.8.7-3	0
B 3.8.1-35	41	B 3.8.7-4	0
B 3.8.1-36	41	B 3.8.8-1	1
B 3.8.1-37	41	B 3.8.8-2	1
B 3.8.1-38	41	B 3.8.8-3	21
B 3.8.1-39	41	B 3.8.8-4	21
B 3.8.1-40	41	B 3.8.8-5	1
B 3.8.1-41	41	B 3.8.9-1	34
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B 3.9.6-1	0		
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BASES

LCO 3.0.3 (continued)

The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken. Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.14, "Fuel Storage Pool Water Level." LCO 3.7.14 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.14 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.14 of "Suspend movement of irradiated fuel assemblies in fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

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

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time.

(continued)

BASES

LCO 3.0.4 (continued)

Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions. LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

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

(continued)

BASES

LCO 3.0.4 (continued)

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

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

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

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

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

(continued)

BASES

LCO 3.0.4 (continued)

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

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

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

LCO 3.0.5

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

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

(continued)

BASES

LCO 3.0.5 (continued)

of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing. An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

LCO 3.0.6

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

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

(continued)

BASES

LCO 3.0.6 (continued)

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

Specification 5.5.15, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

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

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

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

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

(continued)

BASES

LCO 3.0.6 (continued)

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.

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

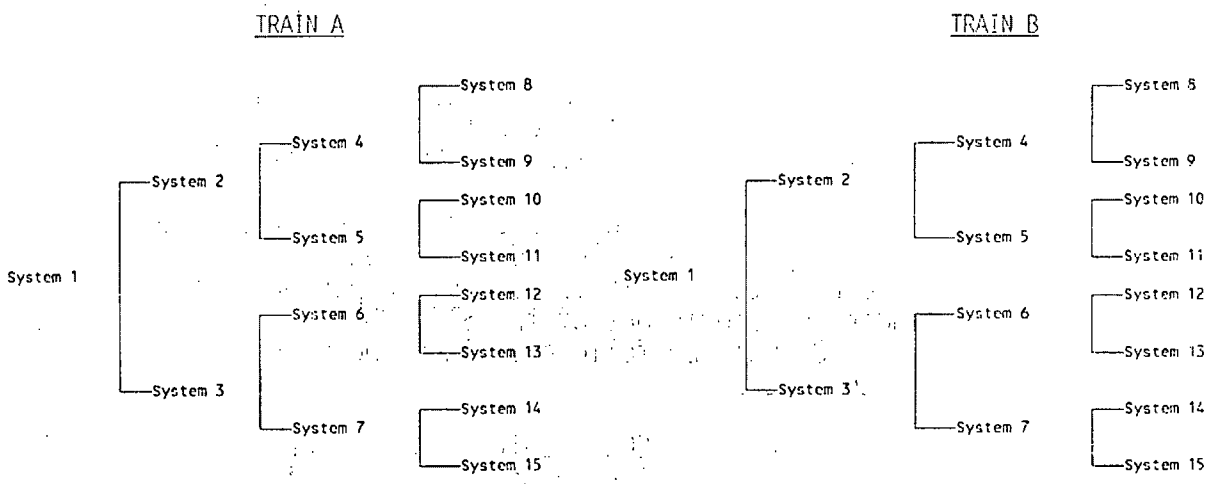
When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due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

(continued)

BASES

LCO 3.0.6
(continued)

EXAMPLES



EXAMPLE B3.0.6-1
If System 2 of Train A is inoperable, and System 5 of Train B is inoperable, a loss of safety function exists in supported Systems 5, 10 and 11.

EXAMPLE B3.0.6-2
If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11 which is in turn supported by System 5.

EXAMPLE B3.0.6-3
If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2,4,5,8,9,10, and 11.

For the examples above, support systems are to the left of the supported systems (i.e., System 1 supports System 2 and System 3).

LCO 3.0.7 Special tests and operations are required at various times over the unit'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

(continued)

BASES

LCO 3.0.7 (continued)

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 LCOs 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.

Some of the STE LCOs require that one or more of the LCOs for normal operation be met (i.e., meeting the STE LCO requires meeting the specified normal LCOs). The Applicability, ACTIONS, and SRs of the specified normal LCOs, 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 LCOs are suspended or changed by the special test, those SRs that are necessary to meet the specified normal LCOs 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 LCOs 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.

(continued)

BASES

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

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

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

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 unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a 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.

(continued)

BASES

SR 3.0.1 (continued)

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

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

Some examples of this process are:

a. Auxiliary Feedwater (AFW) pump turbine maintenance during refueling that requires testing at steam pressures > 800 psi. However, if other appropriate testing is satisfactorily completed, the AFW System can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the testing.

b. 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.

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BASES

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.

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.

(continued)

BASES

SR 3.0.2 (continued)

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

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. Reference Bases Section 3.0.2 for discussion and applicability of Frequency and 25% extension.

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 unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

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

(continued)

BASES

SR 3.0.3 (continued)

specified, the missed Surveillance should be performed at the first reasonable opportunity.

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

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

(continued)

BASES

SR 3.0.3 (continued)

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

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

SR 3.0.4

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

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

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

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

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the

(continued)

BASES

SR 3.0.4 (continued)

SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

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

In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

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

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

b. The core remains subcritical after accident transients.

The most limiting SDM requirements for MODES 1 and 2 at EOC come from Steam Line Break (SLB). The requirements of the SLB event at EOC for both 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 SDM obtained via the scramming of the CEAs are also substantially larger due to the much lower boron concentration at EOC. To verify that adequate SDM 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 differences between available SDM and the limiting SDM requirements are the smallest at these times in the cycle. The measurement of CEA bank worth performed as part of the Startup Testing Program demonstrates that the core has expected shutdown capability. Consequently, adherence to LCOs 3.1.6 and 3.1.7 provides assurance that the available SDM at any time in cycle will exceed the limiting SDM requirements at that time in the cycle.

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

LCO

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

APPLICABILITY

The shutdown CEAs must be within their insertion limits, with the reactor in MODES 1 and 2. The applicability in MODE 2 begins anytime any regulating CEA is not fully inserted. 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. Refer to LCO 3.1.1 and LCO 3.1.2, "SHUTDOWN MARGIN (SDM) - Reactor Trip Breaker Closed," for SDM requirements in MODES 3, 4,

(continued)

BASES (continued)

APPLICABILITY (continued)

and 5. LCO 3.9.1, "Boron Concentration," ensures adequate DM in MODE 6.

This LCO has been modified by a Note indicating the LCO requirement is suspended during SR 3.1.5.3, which verifies the freedom of the CEAs to move, and requires the shutdown CEAs to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1

Prior to entering this Condition, the shutdown CEAs were fully withdrawn. If a shutdown CEA is then inserted into the core, its potential negative reactivity is added to the core as it is inserted.

If the CEA is not within limits, within 2 hours restore the CEA to within limits. The 2 hour total Completion Time allows the operator adequate time to adjust the CEA in an orderly manner and is consistent with the required completion Times in LCO 3.1.5, "Control Element Assembly (CEA) Alignment."

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.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

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

(continued)

BASES (continued)

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10 and GDC 26.
2. 10 CFR 50.46.
3. UFSAR, Section 15.4.

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BASES

ACTIONS (continued)

With a channel process measurement circuit that affects multiple functional units inoperable or in test, bypass or trip all associated functional units as listed below:

Process Measurement Circuit	Functional Unit (Bypassed or Tripped)
1. Linear Power (Subchannel or Linear)	Variable Overpower (RPS) Local Power Density-High (RPS) DNBR-Low (RPS)
2. Pressurizer Pressure-High (Narrow Range)	Pressurizer Pressure-High (RPS) Local Power Density-High (RPS) DNBR-Low (RPS)
3. Steam Generator Pressure-Low	Steam Generator Pressure-Low (RPS) Steam Generator #1 Level-Low (ESF) Steam Generator #2 Level-Low (ESF)
4. Steam Generator Level-Low (Wide Range)	Steam Generator Level-Low (RPS) Steam Generator #1 Level-Low (ESF) Steam Generator #2 Level-Low (ESF)
5. Core Protection Calculator	Local Power Density-High (RPS) DNBR-Low (RPS)

A.1 and A.2

Condition A applies to the failure of a single trip channel or associated instrument channel inoperable in any RPS automatic trip Function. RPS coincidence logic is two-out-of-four.

If one RPS channel is inoperable, startup or power operation is allowed to continue, providing the inoperable channel is placed in bypass or trip in 1 hour (Required Action A.1). The 1 hour allotted to bypass or trip the channel is sufficient to allow the operator to take all appropriate actions for the failed channel and still ensures that the risk involved in operating with the failed channel is acceptable. The failed channel must be restored to OPERABLE status prior to entering MODE 2 following the next MODE 5 entry. With a channel in bypass, the coincidence logic is now in a two-out-of-three configuration.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The Completion Time of prior to entering MODE 2 following the next MODE 5 entry is based on adequate channel to channel independence, which allows a two-out-of-three channel operation since no single failure will cause or prevent a reactor trip.

The intent of this requirement is that should a failure occur that cannot be repaired during power operation, then continued operation is allowed without requiring a plant shutdown. However, the failure needs to be repaired during the next MODE 5 outage. Allowing the unit to exit MODE 5 is acceptable, as the appropriate retest may not be possible until normal operating pressures and temperatures are achieved. If the failure occurs while in MODE 5, then the problem needs to be resolved during that shutdown, and OPERABILITY restored prior to the subsequent MODE 2 entry.

B.1

Condition B applies to the failure of two channels in any RPS automatic trip Function.

Required Action B.1 provides for placing one inoperable channel in bypass and the other channel in trip within the Completion Time of 1 hour. This Completion Time is sufficient to allow the operator to take all appropriate actions for the failed channels while ensuring the risk involved in operating with the failed channels is acceptable. With one channel of protective instrumentation bypassed, the RPS is in a two-out-of-three logic; 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, the second channel is placed in trip.

(continued)

BASES

ACTIONS

B.1 (continued)

This places the RPS in a one-out-of-two logic. If any of the other OPERABLE channels receives a trip signal, the reactor will trip.

One of the two inoperable channels will need to be restored to operable status prior to the next required CHANNEL FUNCTIONAL TEST, because channel surveillance testing on an OPERABLE channel requires that the OPERABLE channel be placed in bypass. However, it is not possible to bypass more than one RPS channel, and placing a second channel in trip will result in a reactor trip. Therefore, if one RPS channel is in trip and a second channel is in bypass, a third inoperable channel would place the unit in LCO 3.0.3.

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

Condition C applies to one automatic bypass removal channel inoperable. If the inoperable operating bypass removal channel for any operating bypass channel cannot be restored to OPERABLE status within 1 hour, the associated RPS channel may be considered OPERABLE only if the operating bypass is not in effect. Otherwise, the affected RPS channel must be declared inoperable, as in Condition A, and the affected automatic trip channel placed in maintenance (trip channel) bypass or trip. The operating bypass removal channel and the automatic trip channel must be repaired prior to entering MODE 2 following the next MODE 5 entry. The Bases for the Required Actions and required Completion Times are consistent with Condition A.

D.1 and D.2

Condition D applies to two inoperable automatic operating bypass removal channels. If the operating bypass removal channels for two operating bypasses cannot be restored to OPERABLE status within 1 hour, the associated RPS channel may be considered OPERABLE only if the operating bypass is not in effect. Otherwise, the affected RPS channels must be declared inoperable, as in Condition B, and the operating bypass either removed or one automatic trip channel placed in maintenance (trip channel) bypass and the other in trip within 1 hour.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

The restoration of one affected bypassed automatic trip channel must be completed prior to the next CHANNEL FUNCTIONAL TEST, or the plant must shut down per LCO 3.0.3 as explained in Condition B.

E.1 (Before CPC Upgrade)

Condition E applies if any CPC cabinet receives a high temperature alarm. There are redundant temperature sensors in each of the four CPC bays. Since CPC bays B and C also house CEAC calculators 1 and 2, respectively, a high temperature in either of these bays requires entry into LCO 3.3.3, Condition C.

If a CPC cabinet high temperature alarm is received, it is possible for an OPERABLE CPC to be affected and not be completely reliable. Therefore, a CHANNEL FUNCTIONAL TEST must be performed on OPERABLE CPCs within 12 hours. The Completion Time of 12 hours is adequate considering the low probability of undetected failure, the consequences of a single channel failure, and the time required to perform a CHANNEL FUNCTIONAL TEST.

E.1 (After CPC Upgrade)

Condition E is entered when the Required Action and associated Completion Time of Condition A, B, C, or D are not met.

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

(continued)

BASES

ACTIONS (continued)

B.1

Condition B applies to the failure of two trip channels or associated instrument channels, in any RPS automatic trip function. Required Action B.1 provides for placing one inoperable channel in bypass and the other channel in trip within the Completion Time of 1 hour. This Completion Time is sufficient to allow the operator to take all appropriate actions for the failed channels and still ensures the risk involved in operating with the failed channels is acceptable. With one channel of protective instrumentation bypassed, the RPS is in a two-out-of-three logic; 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, the second channel is placed in trip. This places the RPS in a one-out-of-two logic. If any of the other OPERABLE channels receives a trip signal, the reactor will trip.

One of the two inoperable channels will need to be restored to OPERABLE status prior to the next required CHANNEL FUNCTIONAL TEST because channel surveillance testing on an OPERABLE channel requires that the OPERABLE channel be placed in bypass. However, it is not possible to bypass more than one RPS channel, and placing a second channel in trip will result in a reactor trip. Therefore, if one RPS channel is in trip and a second channel is in bypass, a third inoperable channel would place the unit in LCO 3.0.3.

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

Condition C applies to one automatic operating bypass removal channel inoperable. If the operating bypass removal channel for the high logarithmic power level operating bypass cannot be restored to OPERABLE status within 1 hour,

(continued)

BASES

ACTIONS

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

the associated RPS channel may be considered OPERABLE only if the operating bypass is not in effect. Otherwise, the affected RPS channel must be declared inoperable, as in Condition A, and the operating bypass either removed or the affected automatic channel placed in trip or maintenance (trip channel) bypass. Both the operating bypass removal channel and the associated automatic trip channel must be repaired prior to entering MODE 2 following the next MODE 5 entry. The Bases for the Required Actions and required Completion Times are consistent with Condition A.

D.1 and D.2

Condition D applies to two inoperable automatic operating bypass removal channels. If the operating bypass removal channels for two operating bypasses cannot be restored to OPERABLE status within 1 hour, the associated RPS channel may be considered OPERABLE only if the operating bypass is not in effect. Otherwise, the affected RPS channels must be declared inoperable, as in Condition B, and the operating bypass either removed or one automatic trip channel placed in maintenance (trip channel) bypass and the other in trip within 1 hour. The restoration of one affected bypassed automatic trip channel must be completed prior to the next CHANNEL FUNCTIONAL TEST or the plant must shut down per LCO 3.0.3, as explained in Condition B. Completion Times are consistent with Condition B.

E.1

Condition E is entered when the Required Actions and associated Completion Times of Condition A, B, C, or D are not met.

(continued)

BASES

ACTIONS (continued)

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

Condition C applies to one automatic operating bypass removal channel inoperable. The only automatic operating bypass removal on an ESFAS is on the Pressurizer Pressure - Low signal. This operating bypass removal is shared with the RPS Pressurizer Pressure – Low bypass removal.

If the bypass removal channel for any operating bypass cannot be restored to OPERABLE status, the associated ESFAS channel may be considered OPERABLE only if the bypass is not in effect. Otherwise, the affected ESFAS channel must be declared inoperable, as in Condition A, and the operating bypass either removed or the bypass removal channel repaired. The Bases for the Required Actions and required Completion Times are consistent with Condition A.

D.1 and D.2

Condition D applies to two inoperable automatic operating bypass removal channels. If the operating bypass removal channels for two operating bypasses cannot be restored to OPERABLE status, the associated ESFAS channel may be considered OPERABLE only if the operating bypass is not in effect. Otherwise, the affected ESFAS channels must be declared inoperable, as in Condition B, and either the operating bypass removed or the bypass removal channel repaired. The restoration of one affected bypassed automatic trip channel must be completed prior to the next CHANNEL FUNCTIONAL TEST or the plant must shut down per LCO 3.0.3, as explained in Condition B. Completion Times are consistent with Condition B.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

If the Required Actions and associated Completion Times of Condition A, B, C, or D cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

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 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.

(continued)

BASES

ACTIONS

A LOVS channel is inoperable when it does not satisfy the OPERABILITY criteria for the channel's function. The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by the plant specific setpoint analysis. Typically, the drift is found to be 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 instrument is set up for adjustment to bring it within specification. If the actual trip setpoint is not within the Allowable Value, the channel is inoperable and the appropriate Conditions must be entered.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, 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.

A.1 and A.2

Condition A applies if one channel per DG bus is inoperable.

If the channel cannot be restored to OPERABLE status, the affected channel should either be bypassed or tripped within 1 hour (Required Action A.1).

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Placing this channel in either Condition ensures that logic is in a known configuration. In trip, the LOVS Logic is one-out-of-three. In bypass, the LOVS Logic is two-out-of-three. The 1 hour Completion Time is sufficient to perform these Required Actions.

Once Required Action A.1 has been complied with, Required Action A.2 allows prior to entering MODE 2 following the next MODE 5 entry to repair the inoperable channel. If the channel cannot be restored to OPERABLE status, the plant cannot enter MODE 2 following the next MODE 5 entry. The time allowed to repair or trip the channel is reasonable to repair the affected channel while ensuring that the risk involved in operating with the inoperable channel is acceptable. The prior to entering MODE 2 following the next MODE 5 entry Completion Time is based on adequate channel independence, which allows a two-out-of-three channel operation since no single failure will cause or prevent a system actuation.

B.1 and B.2

Condition B applies if two channels per DG bus are inoperable.

If the channel cannot be placed in bypass or trip within 1 hour, the Conditions and Required Actions for the associated DG made inoperable by DG – LOVS instrumentation are required to be entered. Alternatively, one affected channel is required to be bypassed and the other is tripped, in accordance with Required Action B.2. This places the Function in one-out-of-two logic. The 1 hour Completion Time is sufficient to perform the Required Actions.

(continued)

BASES

LCO (continued)

For loop and steam generator related variables, the required information is individual loop temperature and individual steam generator level. In these cases two channels are required to be OPERABLE for each loop of steam generator to redundantly provide the necessary information.

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

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

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.10-1. 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.

(continued)

BASES

ACTIONS (continued)

A.1

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

B.1

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.

(continued)

BASES

LCO (continued)

The Remote 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 Remote Shutdown System be placed in operation.

The allowed out of service time is controlled via the applicable system LCOs or administrative controls established by approved plant procedures. For the purpose of this specification, equipment that is disabled in its safe shutdown condition is considered OPERABLE, however, Technical Specifications need to be reviewed for the applicable system LCO impacts on disabled equipment. Therefore, LCO 3.3.11 only needs to be entered when the instrumentation and/or control circuit is actually disabled or inoperable such that it can't be used from the RSP or controlled locally.

If a control circuit is impacted for the performance of a surveillance test, LCO 3.3.11 need not be entered as long as restoration can reasonably be done within the time frame required to meet Shutdown Cooling entry conditions. However, if a clearance is hung for the performance of maintenance on the equipment/control circuit, then the equipment/control circuit is considered inoperable and LCO 3.3.11 needs to be entered. Additionally, the appropriate system LCO/TLCO also needs to be evaluated to determine if entry is required based on current plant conditions.

Refer to the following examples: (NOTE: Entry into the appropriate system LCO/TLCO also needs to be evaluated to determine if entry is required based on current plant conditions.)

- Charging pump CHBP01 has been isolated for pulsation dampener checks. Entry into 3.3.11 is NOT required because the control circuitry for CHBP01 remains operable.

- Charging pump CHBP01 has been declared inoperable because the pump will not respond to the controls located on the switchgear. Entry into 3.3.11 IS required because the control circuitry for CHBP01 does not function properly.

(continued)

BASES

LCO (continued)

- Atmospheric Dump valve SGBHV185 has been isolated via its block valve to snoop for air leakage. Entry into 3.3.11 is NOT required because the control circuitry for SGBHV185 remains operable.

- Auxiliary Feedwater pump AFBP01 has been removed from service for maintenance. The supply breaker has been racked out and the control power fuses rolled to off. Entry into 3.3.11 IS required because the control circuitry for AFBP01 has been disabled.

- "B" Class pressurizer back-up heaters are de-energized for the performance of 36ST-9SA02. Entry into 3.3.11 is NOT required because the control circuitry for the "B" Class heaters remains operable.

- "B" and "D" PK battery chargers are in service. The "BD" swing charger is tagged out for maintenance. Entry into 3.3.11 IS required because the control circuitry for PKB-H16 has been disabled.

APPLICABILITY

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

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the unit is already subcritical and in the condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control become unavailable.

ACTIONS

A Remote Shutdown System division is inoperable when each Function listed in Table 3.3.11-1 is not accomplished by the required number of channels in Table 3.3.11-1 that satisfies the OPERABILITY criteria for the channel's Function. These criteria are outlined in the LCO section of the Bases.

(continued)

BASES

ACTIONS (continued)

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.11-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more instrumentation channels of the Remote Shutdown System are inoperable. This includes any Function listed in Table 3.3.11-1.

The Required Action is to restore the channels to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

Condition B addresses the situation where one or more disconnect or control circuits of the Remote Shutdown System are inoperable. The required disconnect and control circuits are listed in PVNGS controlled documents.

The required Action is to restore the required switch(s)/circuit(s) to OPERABLE status or issue procedure changes that identify alternate disconnect methods or control circuits. The Completion Time for either of the two Actions is 30 days.

(continued)

BASES

ACTIONS (continued)

C.1 and C.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 12 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.

SURVEILLANCE REQUIREMENTS

SR 3.3.11.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION. Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are offscale in the same direction. Current loop channels are verified to be reading at the bottom of the range and not failed downscale.

The Frequency of 31 days is based on 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.

(continued)

LCO (continued)

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

The Note requires that, before an RCP may be started, the secondary side water temperature (saturation temperature corresponding to SG pressure) in each SG is ≤ 100°F above each of the RCS cold leg temperatures. Satisfying this condition will preclude a large pressure surge in the RCS when the RCP is started.

APPLICABILITY

This LCO is applicable in MODE 4 when the temperature of any RCS cold leg is ≤ 214°F during cooldown or ≤ 291°F during heatup, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 214°F during cooldown and 291°F during heatup. The requirements for overpressure protection in MODES 1, 2 and 3, and in MODE 4 above the LTOP System temperatures are covered by LCO 3.4.10, "Pressurizer Safety Valves - MODES 1, 2, and 3," and LCO 3.4.11, "Pressurizer Safety Valves - MODE 4." When the reactor vessel head is off overpressurization cannot occur.

The numerical values for RCS cold leg temperature at which this is applicable do not account for all instrument uncertainty. Use of an indicated value of 217°F or below during cooldown and 294°F or below during heatup ensures that the actual limits will not be exceeded. These values, which include the appropriate instrument uncertainty, are established in the appropriate plant procedures.

LCO 3.4.3 provides the operational P/T limits for all MODES.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

The Applicability is modified by a Note stating when one or more cold legs reach 214°F, this LCO remains applicable during periods of steady state temperature conditions until all RCS cold leg temperatures reach 291°F. Also, if a cooldown is terminated prior to reaching 214°F and a heatup is commenced, this LCO is applicable until all RCS cold leg

(continued)

BASES (continued)

APPLICABILITY (continued)

temperatures reach 291°F. This Note provides clarification about Applicability intent. Since PVNGS uses two different temperatures at which the Shutdown Cooling System suction line relief valves must be placed in service there is some possibility of confusion. This Note clarifies those circumstances where the Shutdown Cooling System suction line relief valves must be placed in service.

A Note prohibits the application of LCO 3.0.4.b to an inoperable LTOP system. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of the risk assessment addressing inoperable the systems and components, should not be applied in this circumstance.

ACTIONS

A.1

In MODE 4 when any RCS cold leg temperature is ≤ 214°F during cooldown or ≤ 291°F during heatup with one Shutdown Cooling System suction line relief valve inoperable, two Shutdown Cooling System suction line relief valves 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 Shutdown Cooling System suction line relief valve 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.

B.1

The consequences of operational events that will overpressure the RCS are more severe at lower temperature (Ref. 6). Thus, one required Shutdown Cooling System suction line relief valve inoperable in MODE 5 or in MODE 6 with the head on, the Completion Time to restore inoperable valve to OPERABLE status is 24 hours.

The 24 hour Completion Time to restore two Shutdown Cooling System suction line relief valves OPERABLE 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 Shutdown

(continued)

ACTIONS (continued)

B.1 (continued)

Cooling System suction line relief valve failures without exposure to a lengthy period with only one Shutdown Cooling System suction line relief valve OPERABLE to protect against overpressure events.

C.1

If two required Shutdown Cooling System suction line relief valves are inoperable, or if a Required Action and the associated Completion Time of Condition A or B are not met, the RCS must be depressurized and a vent established within 8 hours. The vent must be sized at least 16 square inches to ensure the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action protects the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel. For personnel safety considerations, the RCS cold leg temperature must be reduced to less than 200°F prior to venting.

The Completion Time of 8 hours to depressurize and vent the RCS 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 3.4.13.1 and 3.4.13.2

SR 3.4.13.1 and SR 3.4.13.2 require verifying that the RCS vent is open ≥ 16 square inches or that the Shutdown Cooling System suction line relief valves be aligned to provide overpressure protection for the RCS is proven OPERABLE by verifying its open pathway condition either:

Shutdown Cooling System suction/line relief valves

a. Once every 12 hours for a valve that is unlocked, not sealed, or otherwise not secured open in the vent pathway, or

b. Once every 31 days for a valve that is locked, sealed, or otherwise secured open in the vent pathway.

RCS Vent

a. Once every 12 hours for a vent pathway that is unlocked, not sealed, or otherwise not secured open

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 and 3.4.13.2 (continued)

b. Once every 31 days for a vent pathway that is locked, sealed, or otherwise secured open.

For an RCS vent to meet the specified flow capacity, it requires removing all pressurizer safety valves, or similarly establishing a vent by opening the pressurizer manway (Ref. 11). The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open. The passive vent arrangement must only be open (vent pathway exists) to be OPERABLE. These Surveillances need only be performed if the vent or the Shutdown Cooling System suction line relief valves are being used to satisfy the requirements of this LCO. The Frequencies consider operating experience with mispositioning of unlocked and locked pathway vent valves, and passive pathway obstructions.

SR 3.4.13.3

SRs are specified in the Inservice Testing Program. Shutdown Cooling System suction line relief valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 10), which provides the activities and the Frequency necessary to satisfy the SRs. The Shutdown Cooling System suction line relief valve set point is 467 psig.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. UFSAR, Section 15.
4. 10 CFR 50.46.
5. 10 CFR 50, Appendix K.
6. Generic Letter 90-06.
7. UFSAR, Section 5.2.

(continued)

REFERENCES (continued)

8. Pressure Transient Analyses

   a. V-PSAC-009 (3876 MWt w/Original Steam Generators)

   b. MN725-00118 (Unit 2, 4070 MWt w/Replacement Steam Generators)

   c. MN725-00562 (Units 31, 4070 MWt w/Replacement Steam Generators)

9. Mass Input Pressure Transient in Water Solid RCS
   a. V-PSAC-010 (3876 MWt w/Original Steam Generators)

   b. MN725-00117 (Unit 2, 4070 MWt w/Replacement Steam Generators)

   c. MN725-01495 (Units 31,4070 MWt w/Replacement Steam Generators)

10. ASME, Boiler and Pressure Vessel Code, Section XI.

11. 13-COO-93-016, Sensitivity Study on Pressurizer Vent Paths vs. Days Post Shutdown.

12. PVNGS Calculation 13-N001-6.02-652-2.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area 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.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR (C)(2)(ii).

LCO

One method of protecting against large RCS LEAKAGE derives from the ability of instruments to 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 RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor in combination with a particulate and gaseous radioactivity monitor (RU-1) provides an acceptable minimum. It has been determined that it is acceptable to continue to call the containment sump OPERABLE with one containment sump pump out of service.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is ≤ 210°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, the likelihood of leakage and crack propagation is much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

If the containment sump monitor is inoperable, no other form of sampling can provide the equivalent information.

However, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.14.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage.

Restoration of the sump monitor to OPERABLE status is required to regain the function in a Completion Time of 30 days after the monitor's failure. This time is acceptable considering the frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

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

With either the gaseous or particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed, or water inventory balances, in accordance with SR 3.4.14.1, must be performed to provide alternate periodic information. With a sample obtained and analyzed or an inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of both of the radioactivity monitors.

The 24 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

(continued)

BASES

LCO (continued)

The SGTR accident analysis (Ref. 2) shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor 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.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS cold leg 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 RCS cold leg 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 reactor 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 limits of Figure 3.4.17-1 are 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 permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(s) while relying on the ACTIONS.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1

If a Required Action and associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is in the unacceptable region of Figure 3.4.17-1, the reactor must be brought to MODE 3 with RCS cold leg temperature < 500°F within 6 hours. The allowed Completion Time of 6 hours is required to reach MODE 3 below 500°F without challenging plant systems.

C.1 and C.2

With the gross specific activity in excess of the allowed limit, an analysis must be performed within 4 hours to determine DOSE EQUIVALENT I-131. The Completion Time of 4 hours is required to obtain and analyze a sample.

The change within 6 hours to MODE 3 and RCS cold leg temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and minimizes the potential for 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.

(continued)

BASES

A note prohibits the application of LCO 3.0.4.b to an inoperable ECCS high pressure safety injection subsystem. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high pressure safety injection subsystem and the provisions of LCO 3.0.4.b which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

ACTIONS

A.1

With no HPSI pump OPERABLE, the unit is not prepared to respond to a loss of coolant accident. The 1 hour Completion Time to restore at least one HPSI train to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity or to initiate actions to place the unit in MODE 5, where an ECCS train is not required.

B.1

When the Required 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 3.5.4.1

The applicable Surveillance descriptions from Bases 3.5.3 apply as they pertain to the required HPSI train.

REFERENCES

The applicable references from Bases 3.5.3 apply as they pertain to the required HPSI train.

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BASES

APPLICABILITY (continued)

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

The required ACTIONS have been modified by a Note stating that all three PVNGS Units (Units 1, 2, and 3) shall simultaneously comply with the REQUIRED ACTION(s) when the shared portion of the hydrogen recombiner(s) is the cause of a CONDITION. This is necessary since the three PVNGS Units share the two hydrogen recombiners that are required by this LCO. It will be necessary for the Control Room of the Palo Verde Unit that discovers an inoperable shared portion of the hydrogen recombiner(s) to notify the other two Palo Verde Unit's Control Rooms of the inoperability.

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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With two hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the Hydrogen Purge Cleanup System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. In addition, the alternate hydrogen control system capability must be verified every 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check, by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

If the inoperable hydrogen recombiner(s) cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. 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.

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a High Energy Line Break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generator.

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, Steam Bypass Control System, and other auxiliary steam supplies from the steam generators.

The MSIV is a 28-inch gate valve with redundant hydraulic actuator trains. The actuation system is composed of redundant trains A and B. The instrumentation and controls of the train A valve actuator trains are physically and electrically separate and independent of the instrumentation and control of the train B valve actuator trains. Either actuator train can independently perform the safety function to fast-close the MSIV on demand. Each actuator train consists of a hydraulic accumulator controlled by solenoid valves on the associated MSIV.

The MSIVs close on a main steam isolation signal generated by either low steam generator pressure, high steam generator level or high containment pressure. The MSIVs fail closed on loss of control or actuation power. The MSIS also actuates the Main Feedwater Isolation Valves (MFIVs) to close. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the FSAR, Section 10.3 (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, as discussed in the CESSAR, Section 6.2 (Ref. 2). It is also influenced by the accident analysis of the SLB events presented in the UFSAR, Section 15.1.5 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

The limiting case for the containment analysis is the hot zero power SLB inside containment with a loss of offsite power following turbine trip, and failure of the MSIV on the affected steam line to close. At zero power, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to reverse flow, failure of the MSIV to close contributes to the total release of the additional mass and energy in the steam headers, which are downstream of the other MSIVs. With the most reactive control element assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the borated water injection delivered by the Emergency Core Cooling System. Other failures considered are the failure of an MFIV to close, and failure of an emergency diesel generator to start.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot 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 turbine trip.

With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System (RCS) cooldown. With a loss of offsite power, the response of mitigating systems, such as the High Pressure Safety Injection (HPSI) pumps, is delayed. Significant single failures considered include: failure of a MSIV to close, failure of an emergency diesel generator, and failure of a HPSI pump.

(continued)

BASES

LOC (continued)

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.

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, an SGTR is not a credible event.

ACTIONS

A.1

With one required ADV line inoperable, action must be taken to restore the OPERABLE status within 72 hours. The 72 hour Completion Time takes into account the availability of a nonsafety grade backup in the Steam Bypass Control System and MSSVs.

B.1

With two required ADV lines inoperable (one in each steam generator), action must be taken to restore one of the ADV lines to OPERABLE status. As the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ADV lines, based on the availability of the Steam Bypass Control System and MSSVs, and the low probability of an event occurring during this period that requires the ADV lines.

(continued)

BASES

ACTIONS

C.1 and C.2

If the ADV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened and throttled through their full range. This SR ensures the ADVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ADV during a unit cooldown may satisfy this requirement. 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. UFSAR, Section 10.3.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE and to function in the event that the MFW System is lost. In addition, the AFW System is required to supply enough makeup water to replace steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4, the AFW System may be used for heat removal via the steam generator.

In MODES 5 and 6, the steam generators are not normally used for decay heat removal, and the AFW System is not required.

A note prohibits the application of LCO 3.0.4.b to an inoperable AFW Train. There is an increased risk associated with entering a MODE or other specified condition in the applicability with an AFW train inoperable and the provisions of LCO 3.0.4.b which allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

ACTIONS

A.1

If one of the two steam supplies to the turbine driven AFW pumps is inoperable, or if a turbine driven pump is inoperable while in MODE 3 immediately following refueling (prior to MODE 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. For the inoperability of a steam supply to the turbine-driven AFW pump, the 7 day Completion time is reasonable since there is a redundant steam supply line for the turbine driven pump.

b. For the inoperability of a turbine-driven AFW pump while in MODE 3 immediately subsequent to a refueling outage, the 7 day Completion time is reasonable due to the minimal decay heat levels in this situation.

c. For both the inoperability of a steam supply line to the turbine-driven pump and an inoperable turbine-driven AFW pump while in MODE 3 immediately following a refueling outage, the 7 day Completion time is reasonable due to the availability of redundant OPERABLE motor driven AFW pumps.

(continued)

BASES

ACTIONS

A.1 (continued)

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

Condition A is modified by a Note which limits the applicability of the Condition to when the unit has not entered MODE 2 following a refueling. Condition A allows the turbine-driven AFW pump to be inoperable for 7 days vice the 72 hour Completion Time in Condition B. This longer Completion Time is based on the reduced decay heat following refueling and prior to the reactor being critical.

It should be noted that when in this Condition with one steam supply to the turbine driven AFW pump inoperable, that the AFA train of AFW is considered to be inoperable.

B.1

With one of the required AFW trains (pump or flow path) inoperable, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on 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 paths remain to supply feedwater to the 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.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

(continued)

BASES

APPLICABILITY (continued)

The AC power requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are covered in LCO 3.8.2, "AC Sources – Shutdown."

ACTIONS

Condition A applies only when the offsite circuit is unavailable to commence automatic load sequencing in the event of a design basis accident (DBA). In cases where the offsite circuit is available for sequencing, but a DBA could cause actuation of the Degraded Voltage Relays, Condition G applies.

A note prohibits the application of LCO 3.4.0.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b which allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

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

Required Action A.2, which only applies if the train (i.e., ESF bus) cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and include: charging pumps; radiation monitors Train A RU-29 and Train B RU-30 (TS 3.3.9), Train A RU-31 and Train B RU-145; pressurizer heaters (TS 3.4.9); ECCS (TS 3.5.3 and TS 3.5.4); containment spray (TS 3.6.6); containment isolation valves NCA-UV-402, NCB-UV-403, WCA-UV-62, and WCB-UV-61 (TS

(continued)

BASES

ACTIONS

A.2 (continued)

3.6.3); containment hydrogen monitors (TS 3.3.10); hydrogen recombiners (TS 3.6.7); auxiliary feedwater system (TS 3.7.5); essential cooling water system (TS 3.7.7); essential spray pond system (TS 3.7.8); essential chilled water system (TS 3.7.10); control room essential filtration system (TS 3.7.11) control room emergency air temperature control system (TS 3.7.12); ESF pump room air exhaust cleanup system (TS 3.7.13); shutdown cooling subsystems (TS 3.4.6, 3.4.7, 3.4.8, and 3.4.15); and fuel building ventilation. Mode applicability is as specified in each appropriate TS section.

The Completion Time for Required Action A.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. The train has no offsite power supplying its loads; and

b. A required feature on the other train is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature.

(continued)

BASES

ACTIONS

A.2 (continued)

Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. 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 10 days. This could lead to a total of 13 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 10 days (for a total of 23 days) allowed prior to complete restoration of the LCO. The 13 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 13 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

(continued)

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 an offsite circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of redundant required features. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and are identical to those specified in ACTION A.2. Mode applicability is as specified in each appropriate TS section. Redundant required feature failures consist of inoperable features associated 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 allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action.

(continued)

ENCLOSURE 2

PVNGS
Technical Specification Bases
Revision 43

Insertion Instructions and
Replacement Pages

Insertion Instructions for the Technical Specifications Bases Revision 43

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PVNGS

Palo Verde Nuclear Generating Station
Units 1, 2, and 3

Technical Specification Bases

Revision 43
March 14, 2007

PALO VERDE

PVNGS

Palo Verde Nuclear Generating Station
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B 3.4.17-1	0	B 3.5.6-1	0
B 3.4.17-2	27	B 3.5.6-2	1
B 3.4.17-3	42	B 3.5.6-3	0
B 3.4.17-4	42	B 3.5.6-4	24
B 3.4.17-5	0	B 3.5.6-5	27
B 3.4.17-6	0	B 3.6.1-1	0
B.3.4.18-1	38	B 3.6.1-2	35
B.3.4.18-2	40	B 3.6.1-3	0
B.3.4.18-3	38	B 3.6.1-4	29
B.3.4.18-4	38	B 3.6.1-5	29
B.3.4.18-5	38	B 3.6.2-1	0
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B.3.4.18-7	38	B 3.6.2-3	0
B.3.4.18-8	38	B 3.6.2-4	0
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B 3.5.1-6	0	B 3.6.3-2	43
B 3.5.1-7	1	B 3.6.3-3	43
B 3.5.1-8	1	B 3.6.3-4	43
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B 3.6.3-12	43	B 3.7.5-2	0
B 3.6.3-13	43	B 3.7.5-3	40
B 3.6.3-14	43	B 3.7.5-4	27
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B 3.6.5-1	0	B 3.7.6-2	28
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B 3.6.6-4	7	B 3.7.7-5	1
B 3.6.6-5	1	B 3.7.8-1	1
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B 3.6.6-7	1	B 3.7.8-3	1
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B 3.6.6-9	0	B 3.7.9-1	0
B 3.6.7-1	0	B 3.7.9-2	1
B 3.6.7-2	0	B 3.7.9-3	0
B 3.6.7-3	42	B 3.7.10-1	10
B 3.6.7-4	0	B 3.7.10-2	1
B 3.6.7-5	0	B 3.7.10-3	1
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B 3.7.1-5	34	B 3.7.11-4	10
B 3.7.1-6	28 Corrected	B 3.7.11-5	10
B 3.7.2-1	40	B 3.7.11-6	10
B 3.7.2-2	42	B 3.7.12-1	1
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B 3.7.2-6	40	B 3.7.13-1	0
B 3.7.2-7	40	B 3.7.13-2	0
B 3.7.2-8	40	B 3.7.13-3	0
B 3.7.2-9	40	B 3.7.13-4	0
B 3.7.3-1	1	B 3.7.13-5	0
B 3.7.3-2	1	B 3.7.14-1	0
B 3.7.3-3	37	B 3.7.14-2	21
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B 3.8.1-32	41	B 3.8.7-1	0
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B 3.8.1-34	41	B 3.8.7-3	0
B 3.8.1-35	41	B 3.8.7-4	0
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B 3.8.1-39	41	B 3.8.8-4	21
B 3.8.1-40	41	B 3.8.8-5	1
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B 3.9.5-4	16		
B.3.9.5-5	16		
B 3.9.6-1	0		
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B 3.9.7-1	0		
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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

occurs as a result of the post trip return power. Therefore, operation of the plant in conformance with minimum SDM requirements ensures that, should a MSLB occur, control room and offsite radiological dose consequences will remain within licensing basis limits as described in the accident analyses (Ref. 2).

In addition to the limiting MSLB transient, the SDM requirement for MODES 3, 4, and 5 must also protect against:

a. Inadvertent boron dilution;

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

c. CEA ejection.

Each of these is discussed below.

In the inadvertent boron dilution analysis, the amount of reactivity by which the reactor is subcritical is determined by the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. The initial subcritical boron concentration assumed in the analysis corresponds to the minimum SDM requirements. These two values (initial and critical boron concentrations), in conjunction with the configuration of the Reactor Coolant System (RCS) and the assumed dilution flow rate, directly affect the results of the analysis. For this reason the event is most limiting at the beginning of core life when critical boron concentrations are highest.

The startup of an inactive RCP will not result in a "cold water" criticality, even if the maximum difference in temperature exists between the SG and the core. Although this event was considered in establishing the requirements for SDM, it is not the limiting event with respect to the specification limits.

In the analysis of the CEA ejection event, maintaining SDM ensures the reactor remains subcritical following a CEA ejection and, therefore, satisfies the radially averaged enthalpy acceptance criterion considering power redistribution effects.

SHUTDOWN MARGIN is the amount by which the core is subcritical, or would be subcritical immediately following a reactor trip, considering a single malfunction resulting in the highest worth CEA failing to insert. With any full strength CEAs not capable of being fully inserted, the

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	withdrawn reactivity worth of these CEAs must be accounted for in the determination of SDM. The SDM satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).
LCO	The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed 10 CFR 100, "Reactor Site Criterion," 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 CEA positioning (regulating and shutdown CEAs) and through the soluble boron concentration.
APPLICABILITY	In MODES 3, 4 and 5 with the Reactor Trip Breakers Open or the CEA drive system not capable of CEA withdrawal, 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 3.1.6, "Shutdown Control Element Assembly (CEA) Insertion Limits," and LCO 3.1.7. In MODES 3, 4 and 5 with the Reactor Trip Breakers Closed, SDM is addressed by LCO 3.1.2, "SHUTDOWN MARGIN (SDM) - Reactor Trip Breakers Closed." In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration."
ACTIONS	A.1 If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met. In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power. Therefore, operation of the plant in conformance with minimum SDM requirements ensures that, should a MSLB occur, control room and offsite radiological dose consequences will remain within licensing basis limits as described in the accident analysis (Ref. 2).

In addition to the limiting MSLB transient, the SDM requirement for MODES 3, 4, and 5 must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled CEA withdrawal from a subcritical condition;

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

d. CEA ejection.

Each of these is discussed below.

In the inadvertent boron dilution analysis, the amount of reactivity by which the reactor is subcritical is determined by the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. The initial subcritical boron concentration assumed in the analysis corresponds to the minimum SDM requirements. These two values (initial and critical boron concentrations), in conjunction with the configuration of the Reactor Coolant System (RCS) and the assumed dilution flow rate, directly affect the results of the analysis. For this reason the event is most limiting at the beginning of core life when critical boron concentrations are highest.

The withdrawal of CEAs 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 CEAs also produces a time dependent redistribution of core power.

The uncontrolled CEA withdrawal transient is terminated by a high power level trip. Power level, RCS pressure, peak fuel centerline temperature, and the DNBR do not exceed allowable limits.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The startup of an inactive RCP will not result in a "cold water" criticality, even if the maximum difference in temperature exists between the SG and the core. Although this event was considered in establishing the requirements for SDM, it is not the limiting event with respect to the specification limits.

In the analysis of the CEA ejection event, SDM alone cannot prevent reactor criticality following a CEA ejection. At temperatures less than 500 F, the K_{N-1} requirement ensures the reactor remains subcritical and, therefore, satisfies the radially averaged enthalpy acceptance criterion considering power redistribution effects. Above 500 F, Doppler reactivity feedback is sufficient to preclude the need for a specific K_{N-1} requirement.

The function of SHUTDOWN MARGIN is to ensure that the reactor remains subcritical following a design basis accident or anticipated operational occurrence. During operation in MODES 1 and 2, with k_{eff} greater than or equal to 1.0, the transient insertion limits of Specification 3.1.3.6 ensure that sufficient SHUTDOWN MARGIN is available.

SHUTDOWN MARGIN is the amount by which the core is subcritical, or would be subcritical immediately following a reactor trip, considering a single malfunction resulting in the highest worth CEA failing to insert. With any full strength CEAs not capable of being fully inserted, the withdrawn reactivity worth of the CEAs must be accounted for in the determination of SDM.

SHUTDOWN MARGIN requirements vary throughout the core life as a function of fuel depletion and reactor coolant system (RCS) cold leg temperature (T_{cold}). The most restrictive condition occurs at EOL, with T_{cold} at no-load operating temperature, and is associated with a postulated steam line break accident and the resulting uncontrolled RCS cooldown. In the analysis of this accident, the specified SHUTDOWN MARGIN is required to control the reactivity transient and ensure that the fuel performance and offsite dose criteria are satisfied.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

As (initial) T_{cold} decreases, the potential RCS cooldown and the resulting reactivity transient are less severe and, therefore, the required SHUTDOWN MARGIN also decreases. Below T_{cold} of about 350°F, the inadvertent deboration event becomes limiting with respect to the applicable SHUTDOWN MARGIN requirements. Below 350°F, the specified SHUTDOWN MARGIN ensures that sufficient time for operator actions exists between the initial indication of the deboration and the total loss of shutdown margin. Accordingly, with the reactor trip breakers closed and the CEA drive system capable of CEA withdrawal, the SHUTDOWN MARGIN requirements are based upon these limiting conditions.

Additional events considered in establishing requirements on SHUTDOWN MARGIN that are not limiting with respect to the Specification limits are single CEA withdrawal and startup of an inactive reactor coolant pump.

The function of K_{N-1} is to maintain sufficient subcriticality to preclude inadvertent criticality following ejection of a single control element assembly (CEA). K_{N-1} is a measure of the core's reactivity, considering a single malfunction resulting in the highest worth inserted CEA being ejected.

K_{N-1} requirements vary with the amount of positive reactivity that would be introduced assuming the CEA with the highest inserted worth ejects from the core. The K_{N-1} requirement ensures that a CEA ejection event while shutdown will not result in criticality. Above T_{cold} of 500°F, Doppler reactivity feedback is sufficient to preclude the need for a specific K_{N-1} requirement. With all CEAs fully inserted, K_{N-1} and SHUTDOWN MARGIN requirements are equivalent in terms of minimum acceptable core boron concentration.

The requirement prohibiting criticality due to shutdown group CEA movement is associated with the assumptions used in the analysis of uncontrolled CEA withdrawal from subcritical conditions. Due to the high differential reactivity worth of the shutdown CEA groups, the analysis assumes that the initial shutdown reactivity is such that the reactor will remain subcritical in the event of unexpected or uncontrolled shutdown group withdrawal.

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

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BASES

LCO

The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the most limiting analyses that establish the reactivity control requirements of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed 10 CFR 100, "Reactor Site Criterion," 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, K_{N-1}, and criticality due to Shutdown CEA withdrawal are core physics design conditions that can be ensured through CEA positioning (regulating and shutdown CEAs) and through the soluble boron concentration.

APPLICABILITY

In MODES 3, 4, and 5 with the Reactor Trip Breakers Closed and the CEA Drive System is capable of CEA withdrawal, 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 3.1.6, "Shutdown Control Element Assembly (CEA) Insertion Limits," and LCO 3.1.7. MODES 3, 4 and 5 with the Reactor Trip Breakers Open, SDM is addressed by LCO 3.1.1, "SHUTDOWN MARGIN (SDM) - Reactor Trip Breakers Open." In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration."

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 and/or vary CEA position. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on an automatic isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system.

The containment penetration consists of the containment isolation valves and all piping and the associated vent, drain, and test valves located between the containment isolation valves (Ref. 7). All manual vent, drain, and test valves within a Containment Penetration (i.e., between the Containment Isolation Valves) will be maintained locked closed per the locked valve administrative program or surveilled closed per Technical Specification SR 3.6.3.3 or SR 3.6.3.4. Containment penetration isolation criteria are governed by 10 CFR 50, Appendix A, General Design Criteria 54 through 57 (Ref. 6). The applicable GDC for each penetration can be found in UFSAR Table 6.2.4-1 (Ref. 1).

Containment isolation occurs upon receipt of a high containment pressure signal or a low pressurizer pressure signal. The containment isolation signal closes automatic containment isolation valves in fluid penetrations not required for operation of Engineered Safety Feature Systems in order to prevent leakage of radioactive material. Upon actuation of safety injection, automatic containment isolation valves also isolate systems not required for containment or RCS heat removal. Other penetrations are isolated by the use of 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 RCS following a Design Basis Accident (DBA).

(continued)

BASES

BACKGROUND (continued)

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analysis. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the accident analysis will be maintained. All containment isolation valves are considered to be required except for each 42 inch refueling purge valve when its flow path is isolated with a blind flange as allowed by Note 5 under LCO 3.6.3.

The purge valves were designed for intermittent operation, providing a means of removing airborne radioactivity caused by minor RCS leakage prior to personnel entry into containment. There are two sets of purge valves: refueling purge valves and power access purge valves. The refueling and power access supply and exhaust lines are each supplied with inside and outside containment isolation valves but share common supply and exhaust headers.

The refueling purge valves are designed for purging the containment atmosphere to the unit stack while introducing filtered makeup from the outside to provide adequate ventilation for personnel comfort when the unit is shut down during refueling operations and maintenance. Motor operated isolation valves are provided inside and outside the containment. The valves are operated manually from the control room. The valves will close automatically upon receipt of a containment purge isolation actuation signal and a containment isolation actuation signal. Because of their large size, the refueling purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the refueling purge valves are maintained closed in MODES 1, 2, 3, and 4 or the flow paths of the refueling purge valves are isolated with blind flanges to ensure the containment boundary is maintained.

Open refueling purge valves, or a failure of the power access purge valves to close, following an accident that releases contamination to the containment atmosphere would cause a significant increase in the containment leakage rate.

(continued)

BASES

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), a feedwater line break, and a control element assembly 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 refueling purge valves are closed at event initiation.

The DBA analysis assumes that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve stroke times.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. The inboard and outboard isolation valves on each line are provided with diverse power sources.

The refueling purge valves may be unable to close in the environment following a LOCA. Therefore, each of the refueling purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4 or the flow paths of the refueling purge valves are required to be isolated with blind flanges. In this case, the single failure criterion remains applicable to the containment refueling purge valves due to failure in the control circuit associated with each valve. Again, the purge system valve design precludes a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The power access purge valves are capable of closing under accident conditions. Therefore, they are allowed to be open for limited periods during power operation.

The OPERABILITY of main steam safety valves, main steam isolation valves, main feedwater isolation valves, and main steam atmospheric dump valves is covered by Specifications 3.7.1, 3.7.2, 3.7.3 and 3.7.4 respectively.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

Required containment isolation valves, (CIVs) form a part of the containment boundary. A containment penetration is considered to be the area bounded by the inboard and outboard CIVs and includes all valves, piping, and connections within this boundary (e.g., vents, drains, and test connections) (Ref. 7). The containment isolation valve safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA. The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The refueling purge valves must be maintained sealed closed. All manual vent, drain, and test valves within a Containment Penetration (i.e., between the Containment Isolation Valves) will be maintained locked closed per the locked valve administrative program or surveilled closed per Technical Specification SR 3.6.3.3 or SR 3.6.3.4. The valves covered by this LCO are listed with their associated stroke times in the UFSAR (Ref. 1). The analyses assume the containment is isolated within 60 seconds following an isolation signal (CIAS).

All containment isolation valves are considered to be required except for each 42 inch refueling purge valve when its flow path is isolated with a blind flange tested in accordance with SR 3.6.1.1 as allowed by Note 5 under LCO 3.6.3. This is allowed because the blind flange, instead of the valve, provides the function of the containment boundary.

Required CIVs are considered OPERABLE for LCO 3.6.3 when they are closed (i.e., 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. The Steam Generating System and the Containment Pressure Monitoring System are the only credited closed systems at PVNGS. Placement of CIVs in this configuration may impact the operability of the associated system. If the required valve surveillances have lapsed for a CIV secured in its closed

(continued)

BASES

LCO (continued)

position, the CIV is considered OPERABLE for LCO 3.6.3 because it was OPERABLE when it isolated the penetration and it continues to perform its isolation function (Ref. 9). The passive isolation valves or devices are those listed in Reference 2.

The general actions for an inoperable CIV are to isolate the associated penetration with a component that is not susceptible to an active failure (i.e., a passive component). The appropriate LCO 3.6.3 Condition for each CIV is listed in TRM Table 7.0.300. In addition, isolation of an inoperable CIV should be made with a valve(s) having similar leakage criteria to preserve the overall containment leakage rate. For example, if a Type C tested CIV becomes inoperable, a Type C tested valve should be used for isolation purposes. If an inoperable Type C tested CIV cannot be isolated with another Type C tested valve, then another valve may be used to isolate the penetration per LCO 3.6.3, but engineering shall evaluate this condition to ensure the overall CONTAINMENT leakage rate remains valid per the requirements of LCO 3.6.1 (Ref. 8).

Check valves used to isolate a containment penetration are considered secured in their actuated position when flow through the valve is secured and prevented from unintentional operation (i.e., all upstream flow paths are isolated and administratively controlled). This administrative control process will be via use of a permit or the locked valve program for those upstream sources. Certain containment penetrations with multiple piping connections require isolating the upstream source in lieu of crediting the inboard check valve when the CIV outside containment becomes inoperable. The following penetrations are provided as examples:

* AFA-V079 and AFB-V080 - AFW - Pen 75 and 76

* SIE-V113, -V123, -V133, and -V143 - HPSI - Pen 13 through 16

For the above examples, preventing flow through, and unintentional operation of, the inboard check valve would impact multiple trains of equipment; therefore, this condition is undesirable. In that case, the inoperable CIV is isolated using an upstream passive device, the associated train is declared inoperable, the applicable LCO Condition is entered, and the Required Actions performed.

Manual containment isolation valves include those specified in TRM Table 7.0.300, manual valves used to isolate a penetration (including a deactivated, non-automatic valve), and all vents, drains, and test connections located within a containment penetration. Manual containment isolation valves may be opened intermittently under administrative controls. These

(continued)

BASES

LCO (continued)

administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. This operator may have other concurrent duties as long as those duties do not impact the ability to close the valve within 60 seconds when containment isolation is required. The Shift Manager/CRS determines the allowable concurrent duties. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated.

Manual vent, drain and test connection valves within a penetration may be opened under administrative control on only one side of the containment wall. The opening of a manual vent, drain and test connection valve on both sides of the containment wall provides a direct bypass of the containment barrier and would necessitate declaring the penetration inoperable per LCO 3.6.3 and could impact containment operability per LCO 3.6.1.

Containment Isolation Valves (CIVs) required open during accident conditions are considered "dual function" valves and may be secured in the closed position to conservatively comply with LCO 3.6.3. However, a closed CIV would result in entry into the applicable system LCO.

When a CIV required OPEN during accident conditions becomes inoperable, and there is only one CIV in the penetration, and plant and/or equipment conditions do not support securing the CIV in the closed position to restore operability per LCO 3.6.3, an alternate valve (including a non-automatic, non-manual valve) in the piping connected to the affected penetration may be used as an isolation valve to satisfy the requirement of LCO 3.6.3. The alternate valve must be secured in the closed position and prevented from unintentional operation (via PVNGS administrative controls such as the locked valve or clearance and tagging program or the removal of motive power, as appropriate), and any vent/drain valve and test connection within the new boundary must be closed and capped. To ensure penetration integrity, it is only allowable to use an alternate valve as the isolation valve in the affected penetration if the piping between the inoperable CIV and the valve used for penetration isolation have both of the following characteristics:

* A pressure rating equivalent to the containment design pressure (i.e., 60 psig) AND
* The inoperable CIV does not require Type "C" testing (reference the list of CIVs in the Technical Requirements Manual).

(continued)

BASES

LCO (continued)

Alternatively, some "dual function" CIVs may be administratively controlled in their ESF actuated open position (to prevent unintentional operation) to comply with both LCO 3.6.3 and the associated system LCO. When placed in the OPEN position and OPERABLE pursuant to LCO 3.6.3, the control room's ability to remote-manually close the valve for containment isolation must be maintained (i.e., actuating and control power must be retained). The administrative controls prevent a valve from unintentional operation. This position ensures compliance with containment isolation functions specified by General Design Criteria 54 through 57. The valve is inoperable and entry into the applicable action statement of LCO 3.6.3 will be required until the administrative controls are in place. If, for any reason, a CIV is placed in the administratively controlled OPEN position to remain OPERABLE pursuant to LCO 3.6.3, the cause of the condition will be identified and corrected at the earliest opportunity.

Although system limitations preclude placing a number of "dual function" CIVs in the open position, the following valves are subject to being placed in the OPEN position and remaining OPERABLE pursuant to LCO 3.6.3 with administrative controls to prevent unintentional operation and retain the control room's remote-manual closure capability:

* Containment Hydrogen Monitoring CIVs: HPA-HV-007A, HPA-HV-007B, HPB-HV-008A, and HPB-HV-008B

* HPSI Injection Valves: SIB-UV-616, SIA-UV-617, SIB-UV-626, SIA-UV-627, SIB-UV-636, SIA-UV-637, SIB-UV-646, and SIA-UV-647

* LPSI Flow Control Valves: SIB-UV-615, SIB-UV-625, SIA-UV-635, and SIA-UV-645

* RCP Seal Injection Isolation Valve: CHB-HV-255

The following valves are normally OPEN and considered OPERABLE pursuant to LCO 3.6.3 with no additional actions required (i.e., Control Room remote-manual closure capability need not be maintained):

* Containment Pressure Monitoring CIVs: HCA-HV-074, HCB-HV-075, HCC-HV-076, and HCD-HV-077

* Normal Charging Line Isolation Valve: CHA-HV-524

For inoperable Appendix R credited valves secured in the closed position, actions must be taken per PVNGS

(continued)

BASES

LCO (continued)

Administrative Controls to ensure time limitations are not exceeded.

Required purge valves with resilient seals must meet additional leakage rate requirements. The other containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment," as Type C testing.

Each required containment isolation valve shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair, or replacement work is performed on the valve or its associated actuator, control, or power circuit.

This LCO provides assurance that the required containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 42 inch purge valve penetration flow paths, to be unisolated intermittently under administrative controls. This note is also applicable to those penetrations isolated due to an inoperable containment isolation valve and to the operation of manual vents, drains, and test connections within a containment penetration boundary (including those within the 42" purge valve penetrations, but excluding the 42" purge valves themselves). Furthermore, this note is applicable to manual vents, drains, and test connections within the expanded boundaries of a penetration. Manual valves used to isolate a penetration and/or vent, drain and test connection valves within a penetration may be opened under administrative control on only one side of the containment wall. Opening manual valves on both sides of the containment wall such that the containment atmosphere is in direct communication with outside is not permitted. These administrative controls consist of stationing an operator at each opened valve control, who is in continuous communication with the control room, and can close the specified valve within 60

(continued)

BASES

ACTIONS (continued)

seconds; concurrent duties (as determined by the Shift Manager/CRS) do not adversely impact the 60-second criterion. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated.

Due to the size of the containment refueling purge line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, these valves may not be opened under administrative controls. As allowed per SR 3.6.3.1, this restriction does not preclude opening a single refueling purge valve such that the penetration remains isolated.

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. A subsequent inoperable containment isolation valve in a different containment penetration is governed by subsequent Condition entry and application of the associated Required Actions. This Note is not applicable for a second problem identified in a penetration flow path that is already inoperable (i.e., a containment penetration had previously been identified as having an inoperable component); in that case, the initial time constraints are predicated on the first, initial inoperability of the applicable penetration.

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.

A fifth note has been added specifying that when the flow path of a 42 inch purge valve is isolated with a blind flange tested in accordance with SR 3.6.1.1, the valve is not a required containment isolation valve. This is allowed because the blind flange, instead of the valve, provides the function of the containment boundary.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

In the event one required containment isolation valve in one or more penetration flow paths is inoperable except for purge valve leakage not within limit (refer to Action D), 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 (including a de-activated non-automatic valve), a blind flange, and a check valve with flow through the valve secured. Compliance with this Action is established via: 1) Administrative controls (i.e., permit) on the de-activated automatic valve, closed manual valve, blind flange, or check valve, and 2) Administrative controls (i.e., permit or Locked Valve/Breaker/Component Control lock) on vents, drains, and test connections located within the containment penetration. Instruments (i.e., flow/pressure transmitters) located within the penetration that are not removed from service for maintenance nor open to the atmosphere are considered a closed loop portion of the associated penetration; therefore, isolation valves associated with instruments meeting this criteria need not be isolated nor otherwise administratively controlled to comply with the requirements of this Action. 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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.

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.

(continued)

BASES

ACTIONS (continued)

B.1

With two required containment isolation valves in one or more penetration flow paths inoperable except for purge valve leakage not within limit (refer to Action D), 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 (including a de-activated non-automatic valve), and a blind flange. Compliance with this Action is established via: 1) Administrative controls (i.e., permit) on the de-activated automatic valve, closed manual valve, or blind flange, and 2) Administrative controls (i.e., permit or Locked Valve/Breaker/Component Control lock) on vents, drains, and test connections located within the containment penetration. Instruments (i.e., flow/pressure transmitters) located within the penetration that are not removed from service for maintenance nor open to the atmosphere are considered a closed loop portion of the associated penetration; therefore, isolation valves associated with instruments meeting this criteria need not be isolated nor otherwise administratively controlled to comply with the requirements of this Action. 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.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one or more required 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 (including a de-activated non-automatic valve), and a blind flange. Compliance with this Action is established via: 1) Administrative controls (i.e., permit) on the de-activated automatic valve, closed manual valve, or blind flange and 2) Administrative controls (i.e., permit or Locked Valve/Breaker/Component Control lock) on vents, drains, and test connections located within the containment penetration. Instruments (i.e., flow/pressure transmitters) located within the penetration that are not removed from service for maintenance nor open to the atmosphere are considered a closed loop portion of the associated penetration; therefore, isolation valves associated with instruments meeting this criteria need not be isolated nor otherwise administratively controlled to comply with the requirements of this Action. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within the 4 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 only credited closed systems are the Steam Generating and the Containment Pressure Monitoring Systems. This Note is necessary since this Condition is

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

written to specifically address those penetration flow paths which are neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere (10 CFR 50, APP. A, GDC 57).

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.

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

In the event one or more required containment purge valves in one or more penetration flow paths are not within the purge valve leakage limits, purge valve leakage must be restored to within limits, or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve with resilient seals, or a blind flange. A purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.6. Compliance with this Action is established via: 1) Administrative controls (i.e., permit) on the de-activated automatic valve with resilient seals or blind flange, and 2) Administrative controls (i.e., permit or Locked Valve/Breaker/Component Control lock) on vents, drains, and test connections located within the containment penetration. Instruments (i.e., flow/pressure transmitters) located within the penetration that are not removed from service for maintenance nor open to the atmosphere are considered a closed loop portion of the associated penetration; therefore, isolation valves associated with instruments meeting this criteria need not be isolated nor otherwise administratively controlled to comply with the requirements of this Action. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

(continued)

BASES

ACTIONS

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

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those isolation devices outside containment capable of being mispositioned are in the correct position.

For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

For the required containment purge valve with a resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.6 must be performed at least once every 92 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.3.6, 184 days, is based on an NRC initiative, Generic Issue B-20 (Ref. 3). Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown to be acceptable based on operating experience.

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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each required 42 inch containment purge valve is required to be verified sealed closed at 31 day intervals. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. Detailed analysis of the refueling purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A required containment purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power. In this application, the term "sealed" has no connotation of leak tightness. The Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 4), related to containment purge valve use during unit operations. This SR is not required to be met while in Condition D of this LCO. This is reasonable since the penetration flow path would be isolated.

SR 3.6.3.2

This SR ensures that the power access purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The power access purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.3.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside 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, 4 and for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside 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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.4 (continued)

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.

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, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.5

Verifying that the isolation time of each required 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 3.6.3.6

For required containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B (Ref. 5), is required to ensure OPERABILITY. Industry operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. 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. 3).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.6 (continued)

Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that occurring to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

SR 3.6.3.7

Required 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 required automatic containment isolation valve will actuate to its isolation position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency was developed considering it is prudent that this SR be performed only during a unit 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. UFSAR, Section 6.2.4.
2. UFSAR, Section 6.2.6.
3. Generic Issue B-20.
4. Generic Issue B-24.
5. 10 CFR 50, Appendix J, Option B.
6. 10 CFR 50, Appendix A
7. CL Design Basis Manual
8. CRDR 106542
9. CRDR 2326591

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BASES

ACTIONS

A.2 (continued)

Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. 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 10 days. This could lead to a total of 13 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 10 days (for a total of 23 days) allowed prior to complete restoration of the LCO. The 13 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 13 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

(continued)

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 an offsite circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of redundant required features. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and are identical to those specified in ACTION A.2. Mode applicability is as specified in each appropriate TS section. Redundant required feature failures consist of inoperable features associated 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 allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action.

Four hours from the discovery of these events existing concurrently, is acceptable because it minimizes risk while

(continued)

BASES

ACTIONS

B.2 (continued)

allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

If a DG has been declared inoperable and Condition B has been entered, and during that inoperability a new problem with the inoperable DG is discovered, a separate entry into Condition B is not required for the new DG problem. Therefore, the Required Actions of Condition B would not apply to the new DG problem. The new DG problem must be entered into the corrective action program and corrective actions specified in accordance with the corrective action program. Transportability must be addressed in a timely manner in accordance with the corrective action program.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.4

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 10 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.

When utilizing an extended DG Completion Time (a Completion Time greater than 72 hours and less than or equal to 10 days), the compensatory measures listed below shall be implemented. For planned maintenance utilizing an extended Completion Time, the compensatory measures shall be implemented prior to entering Condition B. For an unplanned entry into an extended Completion Time, the compensatory measures shall be implemented without delay.

1. The redundant DG (along with all of its required systems, subsystems, trains, components, and devices) will be verified OPERABLE (as required by TS) and no discretionary maintenance activities will be scheduled on the redundant (OPERABLE) DG.
2. No discretionary maintenance activities will be scheduled on the gas turbine generators (GTGs).
3. No discretionary maintenance activities will be scheduled on the startup transformers.
4. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit utilizing the extended DG Completion Time.
5. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.
6. The GTGs will not be used for non-safety functions (i.e., power peaking to the grid).

(continued)

ENCLOSURE 3

PVNGS
Technical Specification Bases
Revision 44

Insertion Instructions and
Replacement Pages

Insertion Instructions for the Technical Specifications Bases
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PVNGS

Palo Verde Nuclear Generating Station
Units 1, 2, and 3

Technical Specification Bases

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June 20, 2007

PALO VERDE

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BASES

SURVEILLANCE

Trip Path (Initiation Logic) Tests (continued)

During the Matrix Logic and Initiation Logic test, power is applied to the Matrix relay test coils. The test coils prevent an actuation during testing by preventing the Matrix relay contacts in the Initiation Logic from changing state during the test. This does not affect the Operability of the Initiation Logic since only one of the six logic combinations that are available to trip the Initiation Logic are affected during the test because only one Matrix Logic combination can be tested at any time. The remaining five matrix combinations available ensure that a trip in any three channels will de-energize all four Initiation paths.

Manual Trip Tests

This test verifies that the manual trip handswitches are capable of opening contacts in the Actuation Logic as designed.

The Frequency of 92 days is based on the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Ref. 2).

SR 3.3.6.2

Individual ESFAS subgroup relays must also be tested, one at a time, to verify the individual ESFAS components will actuate when required. Proper operation of the individual subgroup relays is verified by de-energizing these relays one at a time using an ARC mounted test circuit. Proper operation of each component actuated by the individual relays is thus verified without the need to actuate the entire ESFAS function.

The 9 months Staggered Test Frequency is based on operating experience and ensures individual relay problems can be detected within this time frame. Considering the large number of similar relays in the ARC, and the similarity in their use, a large test sample can be assembled to verify the validity of this Frequency. The actual justification is based on CEN-403, "ESFAS Subgroup Relay Test Interval Extension (Ref. 3).

If two or more ESFAS subgroup relays fail per Unit in a 12-month period, an evaluation should be performed to determine the adequacy of the surveillance interval. The evaluation should consider the design, maintenance, and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2 (continued)

testing of all ESFAS subgroup relays. If it is determined that the surveillance interval is inadequate for detecting a single relay failure, the surveillance interval should be decreased. The revised surveillance interval should be such that an ESFAS subgroup relay failure can be detected prior to the occurrence of a second failure.

The above guidance for reevaluating ESFAS subgroup relay surveillance test intervals is based on the Safety Evaluation by the Office of Nuclear Reactor Regulation, "Review of CE Owners Group Topical Report CEN-403, Rev. 1, 'ESFAS Subgroup Relay Test Interval Extension'" (Ref. 4).

Some components cannot be tested at power since their actuation might lead to a plant transient, equipment damage, unjustifiable exposure or an unnecessary burden on plant personnel relative to the safety significance of the surveillance. Reference 1 lists similar criteria, from reference 4, for those relays and actuated equipment exempted from testing at power. Relays not tested at power must be tested in accordance with the Note to this SR.

REFERENCES

1. UFSAR, Section 7.3.

2. CEN-327, May 1986, including Supplement 1, March 1989, and Calculation 13-JC-SB-200.

3. CEN-403, "ESFAS Subgroup Relay Test Interval Extension, Revision 1".

4. Safety Evaluation by the Office of Nuclear Reactor Regulation, Review of CE Owners Group Topical Report CEN-403, Rev. 1, "ESFAS Subgroup Relay Test Interval Extension", February 27, 1996.

B 3.3 INSTRUMENTATION

B 3.3.8 Containment Purge Isolation Actuation Signal (CPIAS)

BASES

BACKGROUND

This LCO encompasses the CPIAS, which is an instrumentation channel that performs an actuation function required for plant protection but is not otherwise included in LCO 3.3.6, "Engineered Safety Features Actuation System (ESFAS) Logic and Manual Trip," or LCO 3.3.7, "Diesel Generator (DG) – Loss of Voltage Start (LOVS)."

The CPIAS provides protection from radioactive contamination in the containment in the event a fuel assembly should be severely damaged during handling. It also closes the purge valves during plant operation in response to a Reactor Coolant System (RCS) leak.

The CPIAS will detect any abnormal amounts of radioactive material in the power access and refueling purge exhaust ducts and will initiate purge valve closure to limit the release of radioactivity to the environment. Both the power access purge and refueling purge supply and exhaust valves are closed on a CPIAS when a high radiation level in the power access and refueling purge exhaust ducts is detected.

The CPIAS includes two independent, redundant logic subsystems, including actuation trains. Each train employs a Gamma (area) sensor.

If either sensor exceeds the trip setpoint, both of the CPIAS trains will be actuated (one-out-of-two logic).

Each train actuates a separate series valve in the containment purge supply and return lines. Either train controls sufficient equipment to perform the isolation function. These valves are also isolated on a Containment Isolation Actuation Signal (CIAS).

(continued)

BASES

BACKGROUND (continued)

Trip Setpoints and Allowable Values

Trip setpoints used in the bistables are based on the analytical limits (Ref. 1). The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. The trip setpoints are digitally generated by the radiation monitors. These trips values are not subject to drifts common to trips generated by analog type equipment. The allowable value for this trip is therefore the same as the Trip Setpoints.

Setpoints in accordance with the Allowable Value will ensure that the consequences of Design Basis Accidents will be acceptable, providing the plant is operated from within the LCOs at the onset of the AOO or accident and the equipment functions as designed.

APPLICABLE SAFETY ANALYSES

The CPIAS is a backup to the CIAS Systems in MODES 1, 2, 3, and 4 and will close the containment purge valves in the event of high radiation levels resulting from a primary leak in the containment.

Branch Technical Position CSB 6-4 (Containment Purging During Normal Plant Operations) requires isolation of the power access purge lines in the event of a loss-of-coolant accident to minimize radiation releases and ensure the radiological consequences will not exceed 10 CFR Part 100 guideline values. The CPIAS will close the containment purge valves (if open) in the event of all large and small break LOCA (CEA ejection is a type of small break LOCA) accidents in containment, as described in Reference 1. The CPIAS however, is not required to function during a fuel handling accident to ensure the offsite consequences of radiation accidents in containment are within 10 CFR 100 limits (Ref. 2) as described in the Safety Analysis (Ref. 1).

The CPIAS satisfies the requirements of Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.3

Proper operation of the individual actuation relays is verified by actuating these relays during the CHANNEL FUNCTIONAL TEST of the Actuation Logic every 18 months. This will actuate the Function, operating all associated equipment. Proper operation of the equipment actuated by each train is thus verified. The Frequency of 18 months is based on plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function during any 18 month interval is a rare event. A Note to the SR indicates that this Surveillance includes verification of operation for each actuation relay.

SR 3.3.8.4

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 plant specific setpoint analysis.

The 18 month Frequency is based on plant operating experience with regard to channel OPERABILITY and drift.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.5

Every 18 months, a CHANNEL FUNCTIONAL TEST is performed on the CPIAS Manual Trip channel.

This test verifies that the trip handswitches are capable of opening contacts in the Actuation Logic as designed, de-energizing the initiation relays and providing manual actuation of the Function. The 18 month Frequency is based on operating experience that has shown these components usually pass the Surveillance when performed at a Frequency of once every 18 months.

REFERENCES

1. UFSAR, Chapter 15.

2. 10 CFR 100.

3. "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," NUREG-75/087, Revision 1, 1978, Section 6.2.4, Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operation."

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. This is done utilizing the Essential Spray Pond System (ESPS).

The UHS is the essential spray ponds as discussed in the UFSAR, Section 9.2.5 (Ref. 1). The two principal functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

The basic performance requirements are that a 26 day supply of water be available, and that the design basis temperatures of safety related equipment not be exceeded.

Additional information on the design and operation of the system along with a list of components served can be found in Reference 1.

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on shutdown cooling. Its maximum post accident heat load occurs 20 minutes after a design basis loss of coolant accident (LOCA). Near this time, the unit switches from injection to recirculation, and the containment spray system is required to remove the core decay heat.

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis. The assumptions include: worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and the worst case failure. The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 2), which requires a 30 day supply of cooling water in the UHS. The 26 day supply contained in the two essential spray ponds meets the intent of this requirement.

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

(continued)

BASES

LCO

The UHS is required to be OPERABLE. The UHS is considered OPERABLE if it contains a sufficient volume of water at or below the maximum temperature that would allow the ESPS to operate for at least 26 days with no makeup following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the ESPS. To meet this condition, the UHS temperature should not exceed 89°F and the level of each ESP should not fall below 12 ft usable water depth during normal unit operation. Since the bottom 1.5 ft of the ESPS is required to meet pump submergence requirements, an actual depth of 13.5 ft is needed to meet the 26 day requirement for inventory purposes.

The 12' is the water volume that would be depleted over 26 days following a design basis LOCA if no makeup were available. The thermal performance analysis utilizes the entire volume inventory of the pond(s) since the entire volume is always available as a heat sink.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

When the plant is in other than MODES 1, 2, 3, or 4, the requirements for the UHS shall be consistent with the definition of OPERABILITY, which requires (support) equipment to be capable of performing its related support function(s).

ACTIONS

A.1 and A.2

If the UHS is inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR verifies adequate long term (26 days) cooling can be maintained with no makeup. The level specified also ensures sufficient NPSH is available for operating the ESPS 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 usable (that which can be depleted) water level of each ESP is ≥ 12 ft. A usable water depth of 12 feet requires 13'-6" of actual water depth. The implementing procedure requires the operator to verify that the level is greater than or equal to 13'-6" measured locally at the spray pond or 14' indicated in the control room using installed instrumentation. The difference is a result of instrument uncertainty.

SR 3.7.9.2

This SR verifies that the ESPS is available to cool the EW System to at least its maximum design temperature within the maximum accident or normal design heat loads for 26 days 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 UHS water temperature is 89°F, as indicated in the control room. This value includes allowance for uncertainties.

REFERENCES

1. UFSAR, Section 9.2.5.

2. Regulatory Guide 1.27.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR verifies that there is enough usable fuel oil in the DG Day Tank to run the diesel generator at full load for a minimum of 1 hour plus 10%. The surveillance is on fuel level since there is no direct indicator of volume. Level is read in feet on the Main Control Board indicators or in equivalent units on local DG instrumentation.

The source for the run-time requirement is the UFSAR Sec. 1.8 and Question 9A.9 commitment to ANSI N195-1976. That standard refers to the level at which fuel is automatically added to the tank. For the DG Day Tanks the "pump start" level is above the SR and so is additionally conservative.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 9). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR provided the accumulated water is removed during the performance of this Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

Since the design of the fuel transfer system is such that pumps will operate automatically in order to maintain an adequate volume of fuel oil in the day tank during or following DG testing, a 31 day Frequency is appropriate.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the auto-connected emergency loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the surveillance in MODE 1 or 2 is further amplified to allow the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated

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ENCLOSURE 4

PVNGS
Technical Specification Bases
Revision 45

Insertion Instructions and Replacement Pages

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B 3.8.1-38	45	B 3.8.7-4	0
B 3.8.1-39	45	B 3.8.8-1	1
B 3.8.1-40	45	B 3.8.8-2	1
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B 3.8.9-6	0		
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B 3.9.1-1	34 Corrected		
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 9 ft.-6 inches in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. 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 unit safety analysis.

(continued)

BASES (continued)

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), a feedwater line break, and a control element assembly (CEA) ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air mass per day (Ref. 3). This leakage rate is defined in 10 CFR 50, Appendix J, Option B, as the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a [52.0 psig for units operating at 3876 MWt RTP, and 58.0 psig for unit operating at 3990 MWt RTP], following a design basis LOCA. 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)(ii).

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

SR 3.8.1.2 Note 4 and SR 3.8.1.7 Note 2 state that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions with the engine at normal keep-warm conditions and achieves required voltage and frequency within 10 seconds, and subsequently achieves steady state required voltage and frequency ranges. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 15 (Ref. 5).

A minimum voltage and frequency is specified rather than an upper and a lower limit because a diesel engine acceleration at full fuel (such as during a fast start) is likely to "overshoot" the upper limit initially and then go through several oscillations prior to a voltage and frequency within the stated upper and lower bounds. The time to reach "steady state" could exceed 10 seconds, and be cause to fail the SR. However, on an actual emergency start, the EDG would reach minimum voltage and frequency in ≤ 10 seconds at which time it would be loaded. Application of the load will dampen the oscillations. Therefore, only specifying the minimum voltage and frequency (at which the EDG can accept load) demonstrates the necessary capability of the EDG to satisfy safety requirements without including a potential for failing the Surveillance.

While reaching minimum voltage and frequency (at which the DG can accept load) in ≤ 10 seconds is an immediate test of OPERABILITY, the ability of the governor and voltage regulator to achieve steady state operation, and the time to do so are important indicators of continued OPERABILITY. Therefore, the time to achieve steady state voltage and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

frequency will be monitored as a function of continued OPERABILITY.

The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used. If a modified start is not used, 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads of 90 to 100 percent (4950 - 5500 kW) of the continuous rating of the DG. Consistent with the guidance provided in the Regulatory Guide 1.9 (Ref. 3) load-run test description, the 4950 - 5500 kW band will demonstrate 90 to 100 percent of the continuous rating of the DG. The load band (4950 - 5500 kW) is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing may be performed within the guidance of the generator capability curve.

A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

The normal 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients because of changing bus loads do not invalidate this test. Note 3 indicates that this Surveillance should be conducted on only

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR verifies that there is enough usable fuel oil in the DG Day Tank to run the diesel generator at full load for a minimum of 1 hour plus 10%. The surveillance is on fuel level since there is no direct indicator of volume. Level is read in feet on the Main Control Board indicators or in equivalent units on local DG instrumentation.

The source for the run-time requirement is the UFSAR Sec. 1.8 and Question 9A.9 commitment to ANSI N195-1976. That standard refers to the level at which fuel is automatically added to the tank. For the DG Day Tanks the "pump start" level is above the SR and so is additionally conservative.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 9). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR provided the accumulated water is removed during the performance of this Surveillance.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

Since the design of the fuel transfer system is such that pumps will operate automatically in order to maintain an adequate volume of fuel oil in the day tank during or following DG testing, a 31 day Frequency is appropriate.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit. distribution network to power the auto-connected emergency loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the surveillance in MODE 1 or 2 is further amplified to allow the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated

(continued)

BASES

SURVEILLANCE REQUIREMENTS

OPERABILITY

SR 3.8.1.8 (continued)

OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load, or equivalent load, without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. Train A Normal Water Chiller (at 842 kW) and Train B AFW pump (at 936 kW) are the bounding loads for the DG A and DG B to reject, respectively. These values were established in reference 14. This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As required by IEEE-308 (Ref. 11), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of a typical 5 second load sequence interval associated with sequencing of the largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are the voltage and frequency values the system must meet, within three seconds, following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by a Note. The reason for the Note is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems. This SR is performed in emergency mode (not paralleled to the grid) ensuring that the DG is tested under load conditions that are as close to design basis conditions as possible. This restriction from normally performing the surveillance in Mode 1, 2, 3, or 4 is further amplified to allow the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns), provided an assessment determines that plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

SR 3.8.1.10

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 generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG will not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing is performed using design basis kW loading and maximum kVAR loading permitted during testing. These loads represent the inductive loading that the DG would experience to the extent practicable and is consistent with the guidance of Regulatory Guide 1.9 (Ref. 3). Consistent with the guidance provided in the Regulatory Guide 1.9 full-load rejection test description, the 4950 - 5500 kW band will demonstrate the DG's capability to reject a load equal to 90 to 100 percent of its continuous rating. Administrative limits have been placed upon the Class 1E 4160 V buses due to high voltage concerns. As a result power factors deviating much from unity are currently not possible when the DG runs parallel to the grid while the plant is shutdown. To the extent practicable, VARs will be provided by the DG during this SR.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.8 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. This Note ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a lagging power factor of ≤ 0.89. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. This power factor should be able to be achieved when performing this SR at power and synchronized with offsite power by transferring house loads from the auxiliary transformer to the startup transformer in order to lower the Class 1E bus voltage. Under certain conditions, however, Note 2 allows the surveillance to be conducted at a power factor other than ≤ 0.89. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.89 results in voltages on the emergency busses that are too high. This would occur when performing this SR while shutdown and the loads on the startup transformer are too light to lower the voltage sufficiently to achieve a 0.89 power factor. Under these conditions, the power factor

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

should be maintained as close as practicable to 0.89 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.89 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.89 without exceeding DG excitation limits.

The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

This SR must be performed at a lagging power factor of ≤ 0.89 at least once every 36 months for each DG. The first performance of this SR at a lagging power factor of ≤ 0.89 shall be within 36 months, plus the 9-month allowance of SR 3.0.2, from the date of implementation of the Technical Specification amendment that is adding the power factor testing requirement to this SR.

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, 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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 10 seconds is derived from requirements of the accident analysis. 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 verify the connection and power supply of permanent and auto-connected emergency loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or shutdown cooling (SDC) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified to the extent possible ensuring power is available to the component.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by four Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with the failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system within they are tied together or operated independently for the partial surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Note 3 states that momentary voltage and frequency transients induced by load changes do not invalidate this test. Note 4 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis accident signal (LOCA) signal, and subsequently achieves steady state required voltage and frequency ranges, and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

SR 3.8.1.12.e ensure that permanently connected loads and auto-connected emergency loads (auto-connected through the automatic load sequencer) are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection of permanent and auto-connected emergency loads is intended to satisfactorily show the relationship of these loads to the offsite circuit loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or SDC systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the offsite circuit system to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified to the extent possible ensuring power is available to the component.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Note 3 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that DG and its associated 4.16 KV output breaker noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed, generator differential current, engine low lube oil pressure, and manual emergency stop trip), trip the DG to avert substantial damage to the DG unit. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, requires 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, ≥ 2 hours of which is at a load equivalent to 105 to 110% of the continuous rating of the DG (5775 - 6050 kW) and ≥ 22 hours at a load equivalent to 90 to 100% of the continuous duty rating of the DG (4950 - 5500 kW). The DG starts for this Surveillance can be performed either from normal keep-warm or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR (Note 3 and Note 4).

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing is performed using design basis kW loading and maximum kVAR loading permitted during testing. These

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

loads represent the inductive loading that the DG would experience to the extent practicable and is consistent with the intent of Regulatory Guide 1.9 (Ref. 3). Administrative limits have been placed upon the Class 1E 4160 V buses due to high voltage concerns. As a result, power factors deviating much from unity are currently not possible when the DG runs parallel to the grid while the plant is shutdown. To the extent practicable, VARs will be provided by the DG during this SR. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2 with the DG connected to an offsite circuit:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

This Surveillance is modified by four Notes. Note 1 states that momentary variations due to changing bus loads do not invalidate the test. Note 2 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a lagging power factor of ≤ 0.89. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. This power factor should be able to be achieved when performing this SR at power and synchronized with offsite power by transferring house loads from the auxiliary transformer to the startup transformer in order to lower the Class 1E bus voltage. Under certain conditions, however, Note 2 allows the surveillance to be conducted at a power factor other than ≤ 0.89. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.89 results in voltages on the emergency busses that are too high. This would occur when performing this SR while shutdown, and the loads on the startup transformer are too light to lower the voltage sufficiently to achieve a 0.89 power factor. Under these conditions, the power factor should be maintained as close as practicable to 0.89 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.89 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.89 without exceeding DG excitation limits. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR (Note 3 and Note 4).

This SR must be performed at a lagging power factor of ≤ 0.89 at least once every 36 months for each DG. The first performance of this SR at a lagging power factor of ≤ 0.89 shall be within 36 months, plus the 9-month allowance of SR 3.0.2, from the date of implementation of the Technical Specification amendment that is adding the power factor testing requirement of this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds, and subsequently achieves steady state required voltage and frequency ranges. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.10.

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Per the guidance in Regulatory Guide 1.9, this SR would demonstrate the hot restart functional capability at full-load temperature conditions, after the DG has operated for 2 hours (or until operating temperatures have stabilized) at full load. Momentary transients due to changing bus loads do not invalidate the test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing. Note 3 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, 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. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, in standby operation (running unloaded), the output breaker is open and can receive an autoclose signal on bus undervoltage; and the load sequence timers are reset.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready-to-load operation if a LOCA actuation signal (e.g., simulated SIAS) is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage, in standby operation (running unloaded) with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 12), paragraph 6.2.6(2) and Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.13.

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit 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. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance, and a

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

perturbation of the offsite or onsite system when they are tied together or operated independently for the partial surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.18

Under accident and loss of offsite power conditions 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 due to high motor starting currents. The 1 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 that safety analysis assumptions regarding ESF equipment time delays are not violated. FSAR, Chapter 8 (Ref. 2) provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, takes into consideration unit 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. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18 (continued)

or operated independently for the surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. The Frequency of 18 months takes into consideration unit 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 three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Note 3 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyze values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref.12), and ≥ 59.9 and ≤ 60.5 hertz (Ref.13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.3.2.4 and Regulatory Guide 1.137 (Ref. 9).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. Note 2 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17
2. Updated FSAR, Chapter 8
3. Regulatory Guide 1.9, Revision 3, "Selection, Design, Qualification and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," July 1993.
4. Updated FSAR, Chapter 6
5. Updated FSAR, Chapter 15
6. Regulatory Guide 1.93, "Availability of Electric Power Sources," Revision 0, December 1974.
7. GL 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18
9. Regulatory Guide 1.137, "Fuel Oil Systems for Standby Diesel Generators," Revision 1, October 1979.
10. ANSI C84.1-1982
11. IEEE Standard 308-1974, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

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BASES

REFERENCE (continued)

12. Calculation 13-EC-PE-123, "Diesel Generator voltage meter loop E-PEN-EI-G01/G02 uncertainty calculation."

13. Calculation 13-EC-PE-124, "Diesel Generator frequency meter loop E-PEN-SI-G01/G02 uncertainty calculation."

14. Calculation 13-MC-DG-401