WOLF CREEK
NUCLEAR OPERATING CORPORATION

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RA 06-0036

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

Subject: Docket No. 50-482: Wolf Creek Generating Station Changes to Technical Specification Bases – Revisions 20 through 23

Gentlemen:

The Wolf Creek Generating Station (WCGS) Unit 1 Technical Specifications (TS), Section 5.5.14, "Technical Specifications (TS) Bases Control Program," provide the means for making changes to the Bases without prior NRC approval. In addition, TS Section 5.5.14 requires that changes made without NRC approval be provided to the NRC on a frequency consistent with 10 CFR 50.71(e). The Enclosure provides those changes made to the WCGS TS Bases (Revisions 20 through 23) under the provisions of TS Section 5.5.14 and a List of Effective Pages. This submittal reflects changes from January 1, 2005 through December 31, 2005. There are no commitments contained in this submittal.

If you have any questions concerning this matter, please contact me at (620) 364-4126, or Diane Hooper at (620) 364-4041.

Very truly yours,

for

Kevin J. Moles

KJM/rlt

Enclosure

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Enclosure to RA 06-0036

Wolf Creek Generating Station

Changes to the Technical Specification Bases

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A.1 (continued)

Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those found in the referenced Conditions and Required Actions.

B.1 and B.2.

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

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

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

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

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

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

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ACTIONS

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

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

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

Risk assessments performed pursuant to LCO 3.0.4.b should consider the desirability of enabling the Rod Control System or allowing one or more rods to be other than fully inserted in MODES 3, 4, or 5 while one train of Function 19 (one RTB train), Function 20 (one trip mechanism for one RTB), or Function 21 (one SSPS logic train) is inoperable and the Reactor Trip System is degraded. The risk assessment should assure that, prior to enabling the Rod Control System or allowing one or more rods to be other than fully inserted in MODES 3, 4, 04 5, procedural controls have been implemented to maintain the RCS boron concentration sufficient to preclude criticality with all control rods fully withdrawn. The administrative controls apply prior to making this Applicability change, however, if the Applicability change took place, these controls include immediate actions to borate or insert all rods and disable rod control whenever RCS temperature is below 500°F. This would mitigate any inadvertent rod withdrawal from subcritical transient.

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

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

With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost. Therefore, SR 3.2.4.2 must be performed (Required Action D.1.1) within 12 hours of THERMAL POWER exceeding 75% RTP and once per 12 hours thereafter. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows

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

continued unit operation at power levels > 75% RTP. At power levels ≤ 75% RTP, operation of the core with radial power distributions beyond the design limits, at a power level where DNB conditions may exist, is prevented. The 12 hour Frequency is consistent with the Surveillance Requirement Frequency in LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)." Required Action D.1.1 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors may not be necessary.

The NIS power range detectors provide input to the Rod Control System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 12.

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

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 12 hour time limit is justified in Reference 12.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux - Low;

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E.1 and E.2 (continued)

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

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-three logic for actuation of the two-out-of-four trip logic. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 12.

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 12.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or to increase THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection

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F.1 and F.2 (continued)

functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, the overlap of the Power Range detectors, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

Required Action G.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided the SDM limits of LCOs 3.1.1, 3.1.5, 3.1.6, and 3.4.2 are met.

H.1 Not Used.

I.1

Condition I applies to one inoperable Source Range Neutron Flux trip

BASES

ACTIONS

I.1 (continued)

channel when in MODE 2, below the P-6 setpoint. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

Required Action I.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided the SDM limits of LCOs 3.1.1, 3.1.5, 3.1.6, and 3.4.2 are met.

J.1

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

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

Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status action must be initiated within the same 48 hours to fully insert all rods, 1 additional hour is allowed to place the Rod Control System in a condition incapable of rod withdrawal (e.g., by de-energizing all CRDMs, by opening the RTBs, or de-energizing the motor generator (MG) sets). Once the ACTIONS are completed, the core is in a more stable condition and outside the Applicability of the Condition. The allowance of 48 hours to restore the channel to OPERABLE status or fully insert all rods, and the additional hour to place the Rod Control System in

BASES

ACTIONS

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

a condition incapable of rod withdrawal are reasonable considering the other source range channel remains OPERABLE to perform the safety function and given the low probability of an event occurring during this interval.

L.1, L.2, and L.3

Not Used.

M.1 and M.2

Condition M applies to the following reactor trip Functions:

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

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours.

For the Pressurizer Pressure - Low and Pressurizer Water level - High Functions, placing the channel in the tripped condition, with reactor power above the P-7 setpoint, results in a partial trip condition requiring only one additional channel to initiate a reactor trip.

For the Reactor Coolant Flow - Low function, placing the channel in the tripped condition, when above the P-8 setpoint, results in a partial tripped condition requiring only one additional channel in the same loop to initiate a reactor trip.

Two tripped channels in two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. There is insufficient heat production to generate DNB conditions below the P-7 setpoint.

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ACTIONS

M.1 and M.2 (continued)

The 72 hours allowed to place the channel in the tripped condition is justified in Reference 12. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition M.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 12.

N.1 and N.2

Not Used.

O.1 and O.2

Condition O applies to Turbine Trip on Low Fluid Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 12.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 12.

BASES

ACTIONS (continued)

P.1 and P.2

Condition P applies to Turbine Trip on Turbine Stop Valve Closure. With one or more channel(s) inoperable, the inoperable channel(s) must be placed in the trip condition within 72 hours. For the Turbine Trip on Turbine Stop Valve Closure function, four of four channels are required to initiate a reactor trip; hence, more than one channel may be placed in trip. If the channel(s) cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel(s) in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 12.

Q.1 and Q.2

Condition Q applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status (Required Action Q.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours (Required Action Q.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The 24 hours allowed to restore the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time of 6 hours (Required Action Q.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions are not required when a logic train is being tested under the 4-hour bypass Note of Condition Q). Entry into Condition Q is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition Q is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition Q entry. If this situation were to occur during the 24-hour Completion Time of Required Action Q.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition Q or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

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Q.1 and Q.2 (continued)

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., essential service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

The Required Actions have been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

R.1 and R.2

Condition R applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours are allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24-hour Completion Time is justified in Reference 13. The shutdown Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in Condition C entry if one RTB train is inoperable and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

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R.1 and R.2 (continued)

The Required Actions have been modified by a Note. The Note allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The 4-hour time limit is justified in Reference 13.

Consistent with the requirement in Reference 13 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a RTB train is inoperable for maintenance are included (note that these restrictions are not required when a RTB train is being tested under the 4-hour bypass Note of Condition R). Entry into Condition R is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition R is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition R entry. If this situation were to occur during the 24-hour Completion Time of Required Action R.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable RTB train and exit Condition R or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

- The probability of failing to trip the reactor on demand will increase when a RTB train is removed from service, therefore, systems designed for mitigating an ATWS event should be maintained available. RCS pressure relief (pressurizer PORVs and safeties), auxiliary feedwater flow (for RCS heat removal), AMSAC, and turbine trip are important to alternate ATWS mitigation. Therefore, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a RTB train is inoperable for maintenance.

- Due to the increased dependence on the available reactor trip train when one logic train or one RTB train is inoperable for maintenance, activities that degrade other components of the RTS, including master relays or slave relays, and activities that cause analog channels to be unavailable, should not be scheduled when a logic train or a RTB train is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., essential service water) that support the systems or functions listed in the first two bullets should not be scheduled when a RTB train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

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S.1 and S.2

Condition S applies to the P-6 and P-10 interlocks. With one or more required channel(s) inoperable, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually, e.g., by observation of the associated permissive annunciator window, accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.

T.1 and T.2

Condition T applies to the P-7, P-8, P-9, and P-13 interlocks. With one or more channel(s) or train inoperable, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually, e.g., by observation of the associated permissive annunciator window, accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

U.1 and U.2

Condition U applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

BASES

ACTIONS

U.1 and U.2 (continued)

With the unit in MODE 3, Condition C is entered if the inoperable trip mechanism has not been restored and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to restore the inoperable trip mechanism to OPERABLE status.

The Completion Time of 48 hours for Required Action U.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

SURVEILLANCE REQUIREMENTS

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

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

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

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

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

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the power range channel output every 24 hours. If the calorimetric heat balance calculation results exceed the power channel output by more than + 2% RTP, the power range channel is not declared inoperable, but must be adjusted consistent with the calorimetric heat balance calculation results. If the power range channel output cannot be properly adjusted, the channel is declared inoperable.

If the calorimetric is performed at part-power (< 45% RTP), adjusting the power range channel indication in the increasing power direction will assure a reactor trip below the power range high safety analysis limit (SAL) in USAR Table 15.0-4 (≤ 118% RTP) (Ref. 11). Making no adjustment to the power range channel in the decreasing power direction due to a part-power calorimetric assures a reactor trip consistent with the safety analyses.

This allowance does not preclude making indicated power adjustments, if desired, when the calorimetric heat balance calculation power is less than the power range channel output. To provide close agreement between indicated power and to preserve operating margin, the power range channels are normally adjusted when operating at or near full power during steady-state conditions. However, discretion must be exercised if the power range channel output is adjusted in the decreasing power direction due to a part-power calorimetric (< 45% RTP). This action may introduce a non-conservative bias at higher power levels which could delay an NIS reactor trip until power is above the power range SAL. The cause of the non-conservative bias is the decreased accuracy of the calorimetric at reduced power conditions.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

The primary error contributor to the instrument uncertainty for a secondary side power calorimetric measurement is the feedwater flow measurement, which is determined by a ΔP measurement across a feedwater venturi. While the measurement uncertainty remains constant in ΔP span as power decreases, when translated into flow the uncertainty increases as a square term. Therefore, a 1% flow error at 100% power can approach a 10% flow error at 30% RTP even though the ΔP error has not changed.

Thus, it is required to adjust the setpoint of the Power Range Neutron Flux – High bistables to ≤ 80% RTP: 1) prior to adjustment of the power range channel output in the decreasing power direction due to a part-power calorimetric below 45% RTP; or 2) for a post refueling startup. The evaluation of extended operation at part-power conditions concludes that the potential need to adjust the indication of the Power Range Neutron Flux in the decreasing power direction is quite small, primarily to address operation in the intermediate range about P-10 (nominally 10% RTP) to allow enabling of the Power Range Neutron Flux – Low setpoint and the Intermediate Range Neutron Flux reactor trips. Before the Power Range Neutron Flux – High bistables are reset to ≤ 109% RTP, the power range channel adjustment must be confirmed based on a calorimetric performed at ≥ 45% RTP.

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

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate that a difference between the calorimetric heat balance calculation and the power range channel output of more than + 2% RTP is not expected in any 24 hour period.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted. The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%.

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

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

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

reasonable time frame to limit operation above 50% RTP while completing the procedural steps associated with the surveillance in an orderly manner.

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 62 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test for bypass breakers is included in SR 3.3.1.14. The bypass breaker test shall include a local manual shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 62 days on a STAGGERED TEST BASIS is justified in Reference 13.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 92 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function, including operation of the P-7 permissive which is a logic function only. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 13.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 75% RTP. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to perform flux mapping. The SR is deferred until a scheduled testing plateau above 75% RTP is attained during a power ascension. During a typical power ascension, it is usually necessary to control the axial flux difference at lower power levels through control rod insertion. After equilibrium conditions are achieved at the specified power plateau, a flux map must be taken and the required data collected. The data is typically analyzed and the appropriate excore calibrations completed within 48 hours after achieving equilibrium conditions. An additional time allowance of 24 hours is provided during which the effects of equipment failures may be remedied and any required re-testing may be performed.

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

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 184 days.

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

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3. Note 2 requires that the quarterly COT for the source range instrumentation shall include verification by observation of the associated permissive annunciator window that the P-6 and P-10 interlocks are in their required state for the existing conditions.

The Frequency of 184 days is justified in Reference 13.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, and it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit conditions. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed, e.g., by observation of the associated permissive annunciator window, within 184 days of the Frequencies prior to reactor startup, 12 hours after reducing power below P-10, and four hours after reducing power below P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "12 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "4 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 184 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup, 12 hours after reducing power below P-10, and four hours after reducing power below P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 for more than 12 hours or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 12 hour or the 4 hour limit. These time limits are reasonable, based

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

on operating experience to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for the periods discussed above. The Frequency of 184 days is justified in Reference 13.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 6.

This SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint methodology.

The Frequency of 18 months is based on the assumed calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This does not include verification of time delay relays. These are verified by response time testing per SR 3.3.1.16. Whenever an RTD is replaced in Functions 6 or 7, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 18 months. This SR is modified by three Notes. Note 1 states that neutron detectors are excluded from the CHANNEL CALIBRATION. The source range neutron detectors are maintained based on manufacturer's recommendations. For the intermediate and power range channels, detector plateau curves are obtained, evaluated, and compared to manufacturer's data. Note 2 states that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. Note 3 states that the power and intermediate range detector plateau voltage verification is not required to be current until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 95% RTP. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to perform a meaningful detector plateau voltage verification. The allowance of 72 hours after equilibrium conditions are attained at the testing plateau provides sufficient time to allow power ascension testing to be conducted in a controlled and orderly manner at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE for subsequent use.

The 18 month Frequency is based on past operating experience, which has shown these components usually pass the Surveillance when performed on the 18 month Frequency. The conditions for verifying the power and intermediate range detector plateau voltages are described above. The other remaining portions of the CHANNEL CALIBRATIONS may be performed either during a plant outage or during plant operation.

SR 3.3.1.12

Not Used.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RTS interlocks every 18 months.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.13 (continued)

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, the SI Input from ESFAS, and the Reactor Trip Bypass Breaker undervoltage trip mechanisms. This TADOT is performed every 18 months. The Manual Reactor Trip TADOT shall independently verify the OPERABILITY of the handswitch undervoltage and shunt trip contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip mechanism.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

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

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.16

SR 3.3.1.16 verifies that the individual channel actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in Table B 3.3.1-2. No credit was taken in the safety analyses for those

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

channels with response times listed as N.A. No response time testing requirements apply where N.A. is listed in Table B 3.3.1-2. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor until loss of stationary gripper coil voltage.

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time verification is performed with the time constants set at their nominal values. The response time may be measured by a series of overlapping tests, or other verification (e.g., Ref. 7), such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated response times with actual response time tests on the remainder of the channel. Allocations for response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" (Ref. 7), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

The allocations for sensor response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

As appropriate, each channel's response time must be verified every 18 months on a STAGGERED TEST BASIS. Each verification shall include at least one train such that both trains are verified at least once per 36 months. Testing of the final actuation devices is included in the verification. Response times cannot be determined during unit operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.1.16 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input to the first electronic component in the channel.

REFERENCES

1. USAR, Chapter 7.
2. USAR, Chapter 15.
3. IEEE-279-1971.
4. 10 CFR 50.49.
5. WCNOC Nuclear Safety Analysis Setpoint Methodology for the Reactor Protection System, (TR-89-0001).
6. WCAP-10271-P-A and Supplement 1-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," May 1986.
7. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.
8. WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases," Revision 1, January 1978.
9. IE Information Notice 79-22, "Qualification of Control Systems," September 14, 1979.
10. "Wolf Creek Setpoint Methodology Report," SNP(KG)-492, August 29, 1984.
11. USAR, Table 15.0-4.

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REFERENCES (continued)	12.	WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.
	13.	WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.

TABLE B 3.3.1-1
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	FUNCTION	TRIP SETPOINT[(a)]
1.	Manual Reactor Trip	NA
2.	Power Range Neutron Flux	
	a. High	≤ 109% of RTP
	b. Low	≤ 25% of RTP
3.	Power Range Neutron Flux	
	a. High Positive Rate	≤ 4% of RTP with a time constant ≥ 2 seconds
	b. High Negative Rate	≤ 4% of RTP with a time constant ≥ 2 seconds
4.	Intermediate Range Neutron Flux	≤ 25% of RTP
5.	Source Range Neutron Flux	≤ 10^5 cps
6.	Overtemperature ΔT	See Table 3.3.1-1 Note 1
7.	Overpower ΔT	See Table 3.3.1-1 Note 2
8.	Pressurizer Pressure	
	a. Low	≥ 1940 psig
	b. High	≤ 2385 psig
9.	Pressurizer Water level - High	≤ 92% of instrument span
10.	Reactor Coolant Flow - Low	≥ 89.9% of loop design flow (90,324 gpm)
11.	Not Used	
12.	Undervoltage RCPs	≥ 10578 Vac
13.	Underfrequency RCPs	≥ 57.2 Hz
14.	Steam Generator (SG) Water Level Low - Low	≥ 23.5% of narrow range instrument span
15.	Not Used	
16.	Turbine Trip	
	a. Low Fluid Oil Pressure	≥ 590.00 psig
	b. Turbine Stop Valve Closure	≥ 1% open

TABLE B 3.3.1-1
(Page 2 of 2)

FUNCTION	TRIP SETPOINT[(a)]
17. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	N.A.
18. Reactor Trip System Interlocks	
a. Intermediate Range Neutron Flux, P-6	≥ 1.0E-10 amps
b. Low Power Reactor Trips Block, P-7	N.A.
c. Power Range Neutron Flux, P-8	≤ 48% RTP
d. Power Range Neutron Flux, P-9	≤ 50% RTP
e. Power Range Neutron Flux, P-10	10% RTP
f. Turbine Impulse Pressure, P-13	≤ 10% turbine power
19. Reactor Trip Breakers	N.A.
20. Reactor Trip breaker Undervoltage and Shunt Trip Mechanisms	N.A.
21. Automatic Trip Logic	N.A.

(a) *The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value. This also applies to the Overtemperature ΔT and Overpower ΔT K and τ values.*

TABLE B 3.3.1-2
(Page 1 of 2)

	FUNCTIONAL UNIT	RESPONSE TIME
1.	Manual Reactor Trip	N.A.
2.	Power Range Neutron Flux	
	a. High	≤ 0.5 second[1]
	b. Low	≤ 0.5 second[1]
3.	Power Range Neutron Flux	
	a. High Positive Rate	N.A.
	b. High Negative Rate	≤ 0.5 second[1]
4.	Intermediate Range Neutron Flux	N.A.
5.	Source Range Neutron Flux	N.A.
6.	Overtemperature ΔT	≤ 6.0 seconds[1]
7.	Overpower ΔT	≤ 6.0 seconds[1]
8.	Pressurizer Pressure	
	a. Low	≤ 2.0 seconds
	b. High	≤ 2.0 seconds
9.	Pressurizer Water Level - High	N.A.
10.	Reactor Coolant Flow - Low	
	a. Single Loop (Above P-8)	≤ 1.0 second
	b. Two Loops (Above P-7 and below P-8)	≤ 1.0 second
11.	Not Used	
12.	Undervoltage - Reactor Coolant Pumps	≤ 1.5 seconds
13.	Underfrequency - Reactor Coolant Pumps	≤ 0.6 second
14.	Steam Generator Water Level - Low-Low	≤ 2.0 seconds
15.	Not Used	

[1] Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

TABLE B 3.3.1-2
(Page 2 of 2)

FUNCTIONAL UNIT	RESPONSE TIME
16. Turbine Trip	
a. Low Fluid Oil Pressure	N.A.
b. Turbine Stop Valve Closure	N.A.
17. Safety Injection Input for ESF	N.A.
18. Reactor Trip System Interlocks	N.A.
19. Reactor Trip Breakers	N.A.
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	N.A.
21. Automatic Trip and Interlock Logic	N.A.

BASES

ACTIONS

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

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

This action addresses the train orientation of the SSPS and the master and slave relays. This action also addresses the effect on containment purge when Phase A is inoperable. Phase A is the primary signal to ensure closing of the containment purge supply and exhaust valves in MODES 1 - 4. If one Phase A train is inoperable, operation may continued as long as the Required Action to place and maintain containment purge supply and exhaust valves in their closed position is met. Required Action C.1 is modified by a Note that this Action is only required if Containment Phase A Isolation (Function 3.a.(2)) is inoperable.

If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 5 within an additional 30 hours (60 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of Ref. 7 that 4 hours is the average time required to perform train surveillance.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions

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ACTIONS

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

are not required when a logic train is being tested under the 4-hour bypass Note of Condition C). Entry into Condition C is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition C is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition C entry. If this situation were to occur during the 24-hour Completion Time of Required Action C.2, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition C or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.
- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.
- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.
- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., essential service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

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ACTIONS (continued)

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

Condition D applies to:

- Containment Pressure - High 1;
- Pressurizer Pressure - Low;
- Steam Line Pressure - Low;
- Containment Pressure - High 2;
- Steam Line Pressure - Negative Rate - High; and
- SG Water Level - Low Low.

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic (excluding Pressurizer Pressure - Low and SG Water Level - Low Low). Therefore, failure of one channel (i.e., with the bistable not tripped) places the Function in a two-out-of-two configuration. The inoperable channel must be tripped to place the Function in a one-out-of- two configuration that satisfies redundancy requirements. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 12.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. The 12 hours allowed for testing are justified in Reference 12.

BASES

ACTIONS (continued)

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

Condition E applies to:

- Containment Spray Containment Pressure - High 3; and
- Containment Phase B Isolation Containment Pressure - High 3.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 72 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows one additional channel to be bypassed for up to 12 hours for surveillance testing. Placing a second channel in the bypass condition for up to 12 hours for testing purposes is acceptable based on the results of Reference 12.

BASES

ACTIONS (continued)

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

Condition F applies to:

- Manual Initiation of Steam Line (fast close) Isolation; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

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

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

BASES

ACTIONS

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

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform train surveillance.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions are not required when a logic train is being tested under the 4-hour bypass Note of Condition G). Entry into Condition G is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition G is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition G entry. If this situation were to occur during the 24-hour Completion Time of Required Action G.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition G or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.

Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., essential service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

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ACTIONS

H.1 and H.2

Condition H applies to the automatic actuation logic and actuation relays for the Turbine Trip and Feedwater Isolation Function.

This action addresses the train orientation of the SSPS and the master and slave relays for this Function. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform train surveillance.

I.1 and I.2

Condition I applies to:

- SG Water Level - High High (P-14);

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-three logic will result in actuation. The 72 hour Completion Time is justified in Reference 12. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit to be placed in MODE 3 within the following 6 hours.

BASES

ACTIONS

I.1 and I.2 (continued)

The allowed Completion Time of Required Action I.2 is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 12.

J.1 and J.2

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

This action addresses the train orientation of the BOP ESFAS for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 1 hour is allowed to place the channel in the tripped condition. If the channel cannot be tripped in 1 hour, 6 additional hours are allowed to place the unit in MODE 3. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above. The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 2 hours for surveillance testing of other channels.

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

Condition K applies to the RWST Level - Low Low Coincident with Safety Injection Function.

RWST Level - Low Low Coincident with SI provides actuation of switchover to the containment recirculation sumps. Note that this Function requires the bistables to energize to perform their required

BASES

ACTIONS

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

action. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 72 hours is sufficient to ensure that the Function remains OPERABLE, and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 72 hour Completion Time is justified in References 11 and 12. If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 72 hours the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows placing a second channel in the tripped condition for up to 12 hours for surveillance testing. Placing a channel in the tripped condition for up to 12 hours for testing purposes is acceptable based on References 11 and 12 (and the license amendment implementing Reference 12).

L.1, L.2.1, and L.2.2

Condition L applies to the P-11, interlock. With one or more required channel(s) inoperable, the operator must verify that the interlock is in the required state for the existing unit condition by observation of the associated permissive annunciator window. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power

BASES

ACTIONS

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

conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlock.

M.1 and M.2

Condition M applies to the Auxiliary Feedwater Pump Suction Transfer on Low Suction Pressure Function. The condensate storage tank is the highly reliable and preferred suction source for the AFW pumps. This function has a 2 out of 3 trip logic. Therefore, continued operation is allowed with one inoperable channel until the performance of the next monthly COT on one of the other channels, as long as the inoperable channel is placed in trip within 1 hour.

N.1 and N.2

Condition N applies to the Auxiliary Feedwater Balance of Plant ESFAS automatic actuation logic and actuation relays. With one train inoperable, the unit must be brought to MODE 3 within 6 hours and MODE 4 within the following 6 hours. The Required Actions are modified by a Note that allows one train to be bypassed for up to 2 hours for surveillance testing provided the other train is OPERABLE.

O.1

Condition O applies to the Auxiliary Feedwater Manual Initiation Function. The associated auxiliary feedwater pump(s) must be declared inoperable immediately when one or more channel(s) is inoperable. Refer to LCO 3.7.5, "Auxiliary Feedwater (AFW) System."

P.1, P.2.1, and P.2.2

Condition P applies to the Auxiliary Feedwater Loss of Offsite Power Function. With the inoperability of one or both train(s), 48 hours is allowed to return the train(s) to OPERABLE status. The specified Completion Time is reasonable considering the fact that this Function is associated only with the turbine driven AFW pump, the available

BASES

ACTIONS

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

redundancy provided by the motor driven AFW pumps, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and in MODE 4 within the following 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the turbine driven AFW pump for mitigation.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

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

SR 3.3.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.2.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 92 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 13.

SR 3.3.2.3

SR 3.3.2.3 is the performance of an ACTUATION LOGIC TEST using the BOP ESFAS automatic tester. The continuity check does not have to be performed, as explained in the Note. This SR is applied to the balance of plant actuation logic. This test is required every 31 days on a STAGGERED TEST BASIS. The Frequency is adequate based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.4 (continued)

large enough to demonstrate signal path continuity. This test is performed every 92 days on a STAGGERED TEST BASIS. The time allowed for the testing (4 hours) is justified in Reference 7. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 13.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

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

The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The Frequency of 184 days is justified in Reference 13.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation by the slave relay blocking circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 92 days. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data. The SR is modified by a Note that excludes slave relays K602, K620, K622, K624, K630, K740, and K741 which are included in testing required by SR 3.3.2.13 and SR 3.3.2.14.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT every 18 months. This test is a check of the Loss of Offsite Power function. The trip actuating devices tested within the scope of SR 3.3.2.7 are the LSELS output relays and

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.7 (continued)

BOP ESFAS separation groups logic associated with the auto-start of the turbine driven AFW pump upon an ESF bus undervoltage condition.

The SR is modified by a Note that excludes verification of setpoints for relays. The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data and is consistent with the typical refueling cycle. The trip actuating devices tested have no associated setpoint.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions (SSPS) and AFW pump start on trip of all MFW pumps BOP ESFAS. The Manual Safety Injection TADOT shall independently verify OPERABILITY of the handswitch undervoltage and shunt trip contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers as well as the contacts for safety injection actuation. It is performed every 18 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.9

SR 3.3.2.9 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology.

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

The Frequency of 18 months is based on the assumed calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

This SR is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This does not include verification of time delay relays. These are verified by response time testing per SR 3.3.2.10.

SR 3.3.2.10

This SR verifies the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time verification acceptance criteria are included in Table B 3.3.2-2. Table B 3.3.2-2 format is based on the initiating trip signal. No credit was taken in the safety analyses for those channels with response times listed as N.A. No response time testing requirements apply where N.A. is listed in Table B 3.3.2-2. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time verification is performed with the time constants set at their nominal values. The response time may be verified by a series of overlapping tests, or other verification (e.g., Ref. 8), such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" (Ref. 7), provides the basis and methodology for using allocated sensor

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.10 (continued)

response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

The allocations for sensor response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

The NRC approved the use of ASME Code Case OMN-1, "Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light-Water Reactor Plants," as an alternative to stroke time testing for motor-operated valves (Ref. 14). The parameters that must be present to achieve the analyzed response time under design basis conditions are measured to ensure the valve is capable of performing its safety function. This process verifies design basis capability, including response time, and is a significant improvement over simple stroke time measurement. This process allows the establishment of periodic valve test intervals if there is assurance that the valve will remain capable of performing its safety function throughout the interval.

ESF response times specified in Table B 3.3.2-2 which include sequential operation of RWST and VCT valves (Notes 3 and 4) are based on values assumed in the non-LOCA safety analyses. These analyses take credit for injection of borated water from the RWST. Injection of borated water is assumed not to occur until the VCT charging pump suction valves are closed following opening of the RWST charging pump suction valves. When the sequential operation of the RWST and VCT valves is not included in the response times (Note 7), the values specified are based on the LOCA analyses. The LOCA analyses take credit for injection flow regardless of the source. Verification of the response times specified in Table B 3.3.2-2 will assure that the assumptions used for the LOCA and non-LOCA analyses with respect to the operation of the VCT and RWST valves are valid.

ESF RESPONSE TIME verification is performed on an 18 month STAGGERED TEST BASIS. Each verification shall include at least one train such that both trains are verified at least once per 36 months. Testing of the final actuation devices, which make up the bulk of the

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.10 (continued)

response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 900 psig in the SGs.

SR 3.3.2.11

SR 3.3.2.11 is the performance of a TADOT as described in SR 3.3.2.8, except that it is performed for the P-4 Reactor Trip Interlock, and the Frequency is every 18 months. This Frequency is based on operating experience.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint. This TADOT does not include the circuitry associated with steam dump operation since it is control grade circuitry.

SR 3.3.2.12

SR 3.3.2.12 is the performance of a monthly COT on ESFAS Function 6.h, "Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low."

A COT is performed to ensure the channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

SR 3.3.2.13

SR 3.3.2.13 is the performance of a SLAVE RELAY TEST as described in SR 3.3.2.6, except that SR 3.3.2.13 has a Note specifying that it applies

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.13 (continued)

only to slave relays K602, K622, K624, K630, K740, and K741. These slave relays are tested with a Frequency of 18 months and prior to entering MODE 4 for Functions 1.b, 3.a.(2), and 7.a whenever the unit has been in MODE 5 or 6 for > 24 hours, if not performed within the previous 92 days (Reference 9). The 18 month Frequency for these slave relays is based on the need to perform this Surveillance under the conditions that apply during a unit outage to avoid the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

SR 3.3.2.14

SR 3.3.2.14 is the performance of a SLAVE RELAY TEST as described in SR 3.3.2.6, except that SR 3.3.2.14 has a Note specifying that it applies only to slave relay K620. The SLAVE RELAY TEST of relay K620 does not include the circuitry associated with the main feedwater pump trip solenoids since that circuitry serves no required safety function. This slave relay is tested with a Frequency of 18 months and prior to entering MODE 2 for Function 5.a whenever the unit has been in MODE 5 or 6 for > 24 hours, if not performed within the previous 92 days (Reference 9). The 18 month Frequency for this slave relay is based on the need to perform this Surveillance under the conditions that apply during a unit outage to avoid the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 7.
3. USAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. WCNOC Nuclear Safety Analysis Setpoint Methodology for the Reactor Protection System, TR-89-0001.
7. WCAP-10271-P-A Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," June 1990.
8. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

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REFERENCES (continued)

9. SLNRC 84-0038 dated February 27, 1984.
10. "Wolf Creek Setpoint Methodology Report," SNP (KG)-492, August 29, 1984.
11. Amendment No. 43 to Facility Operating License No. NPF-42, March 29, 1991.
12. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.
13. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.
14. 10 CFR 50.55a(b)(3)(iii), Code Case OMN-1.

TABLE B 3.3.2-1
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FUNCTION	TRIP SETPOINT[a]
1. Safety Injection	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure – High-1	≤ 3.5 psig
d. Pressurizer Pressure - Low	≥ 1830 psig
e. Steam Line Pressure - Low	≥ 615 psig
2. Containment Spray	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure - High-3	≤ 27.0 psig
3. Containment Isolation	
a. Phase A Isolation	
(1) Manual Initiation	N.A.
(2) Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
(3) Safety Injection	See Function 1 (Safety Injection)
b. Phase B Isolation	
(1) Manual Initiation	N.A.
(2) Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
(3) Containment Pressure - High-3	≤ 27.0 psig
4. Steam Line Isolation	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure - High-2	≤ 17.0 psig
d. Steam Line Pressure	
(1) Low	≥ 615 psig
(2) Negative Rate - High	≤ 100 psi

TABLE B 3.3.2-1
(Page 2 of 2)

FUNCTION	TRIP SETPOINT[a]
5. Turbine Trip and Feedwater Isolation	
a. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
b. SG Water Level - High High	≤ 78% of narrow range instrument span
c. Safety Injection	See Function 1 (Safety Injection)
6. Auxiliary Feedwater	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	N.A.
d. SG Water Level - Low-Low	≥ 23.5% of narrow range instrument span
e. Safety Injection	See Function 1 (Safety Injection)
f. Loss of Offsite Power	N.A.
g. Trip of all Main Feedwater Pumps	N.A.
h. Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low	≥ 21.60 psia
7. Automatic Switchover to Containment Sump	
a. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
b. Refueling Water Storage Tank (RWST) Level - Low Low	≥ 36% of instrument span
Coincident with Safety Injection	See Function 1 (Safety Injection)
8. ESFAS Interlocks	
a. Reactor Trip, P-4	N.A.
b. Pressurizer Pressure, P-11	≤ 1970 psig

[a] The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

Table B 3.3.2-2
(Page 1 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Phase "A" Isolation	N.A.
d. Phase "B" Isolation	N.A.
e. Containment Purge Isolation	N.A.
f. Steam Line Isolation	N.A.
g. Feedwater Isolation	N.A.
h. Auxiliary Feedwater	N.A.
I. Essential Service Water	N.A.
j Containment Cooling	N.A.
k. Control Room Isolation	N.A.
l. Reactor Trip	N.A.
m. Emergency Diesel Generators	N.A.
n. Component Cooling Water	N.A.
o. Turbine Trip	N.A.
2. Containment Pressure - High-1	
a. Safety Injection (ECCS)	≤ 29(7)/27(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation	≤ 1.5(5)
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	≤ 60(1)
6) Containment Cooling	≤ 60(1)
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	≤ 14(6)
9) Turbine Trip	N.A.
3. Pressurizer Pressure - Low	
a. Safety Injection (ECCS)	≤ 29(7)/27(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation	≤ 2(5)
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	≤ 60(1)
6) Containment Cooling	≤ 60(1)
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	≤ 14(6)
9) Turbine Trip	N.A.

Table B 3.3.2-2
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INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
4. Steam Line Pressure - Low	
a. Safety Injection (ECCS)	$\leq 39^{(3)}/27^{(4)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation	$\leq 2^{(5)}$
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	$\leq 60^{(1)}$
6) Containment Cooling	$\leq 60^{(1)}$
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	$\leq 14^{(6)}$
9) Turbine Trip	N.A.
b. Steam Line Isolation	$\leq 2^{(5)}$
5. Containment Pressure - High-3	
a. Containment Spray	$\leq 32^{(1)}/20^{(2)}$
b. Phase "B" Isolation	≤ 31.5
6. Containment Pressure - High-2	
Steam Line Isolation	$\leq 2^{(5)}$
7. Steam Line Pressure - Negative Rate-High	
Steam Line Isolation	$\leq 2^{(5)}$
8. Steam Generator Water Level - High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	≤ 7
9. Steam Generator Water Level - Low-Low	
a. Start Motor Driven Auxiliary Feedwater Pumps	≤ 60
b. Start Turbine Driven Auxiliary Feedwater Pumps	≤ 60
10. Loss-of-Offsite Power	
Start Turbine Driven Auxiliary Feedwater Pumps	≤ 60
11. Trip of All Main Feedwater Pumps	
Start Motor Driven Auxiliary Feedwater Pumps	N.A.

Table B 3.3.2-2
(Page 3 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
12. Auxiliary Feedwater Pump Suction Pressure-Low	
Transfer to Essential Service Water	$\leq 60^{(1)}$
13. RWST Level-Low-Low Coincident with Safety Injection	
Automatic Switchover to Containment Sump	≤ 60

TABLE NOTATIONS

(1) Diesel generator starting and sequence loading delays included.

(2) Diesel generator starting delay not included. Offsite power available.

(3) Diesel generator starting and sequence loading delay included. RHR pumps not included. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is included.

(4) Diesel generator starting and sequence loading delays not included. Offsite power available. RHR pumps not included. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is included.

(5) Does not include valve closure time.

(6) Includes time for diesel to reach full speed.

(7) Diesel generator starting and sequence loading delays included. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is not included. Response time assumes only opening of RWST valves.

BASES

LCO (continued)

8. Steam Line Pressure

Steam Line Pressure is a Type A, Category 1 variable for event diagnosis, natural circulation, and RCP trip criteria. It is a variable for determining if a secondary pipe rupture has occurred. This indication is provided to aid the operator in determining the faulted steam generator and to verify natural circulation.

9. Containment Radiation Level (High Range, GT-RIC-59, -60)

Containment Radiation Level is a Type A, Category 1 variable provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.

10. Not Used.

11. Pressurizer Water Level

Pressurizer Water Level is a Type A, Category 1 variable used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

12. Steam Generator Water Level (Wide Range)

SG Water Level (Wide Range) is a Category 1 variable provided to monitor SG dryout and as a criterion for establishing feed and bleed cooling of the RCS. The wide range level indicator for each steam generator is located in the main control room. Wide range steam generator level measurement meets the intent of the single failure criterion for Category 1 variables by virtue of independent diverse variables. In the emergency procedures, auxiliary feedwater (AFW) flow, reactor coolant pressure, and reactor coolant temperature indications are diverse variables which are

BASES

LCO

12. Steam Generator Water Level (Wide Range) (continued)

used to determine whether adequate core cooling is provided in the absence of wide range level indication for a steam generator. The design limitation of having one wide range level indicator in conjunction with one AFW flow indicator per steam generator is consistent with NUREG-0737, Item II.E.1.2 (Reference 8). Wide range steam generator level is not a Type A variable.

SG Water Level (Wide Range) is used to:

- verify that the intact SGs are an adequate heat sink for the reactor;
- determine the nature of the accident in progress (e.g., verify SGTR overfill); and
- verify unit conditions for termination of SI during secondary unit HELBs outside containment.

13. Steam Generator Water Level (Narrow Range)

Steam Generator Water Level (Narrow Range) is a Type A, Category 1 variable for Steam Generator Tube Rupture event diagnosis and SI termination.

SG Water Level (Narrow Range) is used to:

- identify the affected SG following a tube rupture;
- determine the nature of the accident in progress (e.g., verify an SGTR); and
- verify unit conditions for termination of SI during secondary unit HELBs outside containment.

14, 15, 16, 17. Core Exit Temperature

Core exit temperature is a Category 1 variable which provides for verification and long term surveillance of core cooling.

An evaluation was made in support of Reference 2 of the minimum number of valid core exit thermocouples (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and

BASES

ACTIONS (continued)

tracked separately for each Function starting from the time the Condition was entered for that Function. When the Required Channels in Table 3.3.3-1 are specified on a per SG basis, then the Condition may be entered separately for each SG.

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.8, which requires a written report to be submitted to the NRC within the following 14 days. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two or more inoperable required channels (i.e., two or more channels inoperable in the same Function). Required Action C.1 requires restoring all but one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two or more required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance

BASES

ACTIONS (continued)

C.1 (continued)

qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of all but one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

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

E.1 and E.2

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

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

F.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed. These alternate means may be temporarily used if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. Monitoring the core exit thermocouples, pressurizer level indication (BB-LI-0459A, -0460A, or -0461) and RCS subcooling monitor indication (BB-TI-1390A or B) provide an alternate means for RVLIS. These 3 parameters provide diverse information to verify there is adequate core cooling. When Containment Radiation Level (High Range) monitors are inoperable, portable survey equipment with the capability to detect gamma radiation over the range 1E-03 to 1E04 provides an alternate means (Ref. 5).

SURVEILLANCE REQUIREMENTS

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

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measure parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. Containment Radiation Level (High Range) CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source. The Frequency is based on operating experience and consistency with the typical industry refueling cycle. Whenever an RTD is replaced in Functions 2 or 3, the next required CHANNEL CALIBRATION of the RTD's is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. Whenever a core exit thermocouple is replaced in Functions 14, 15, 16, or 17, the next required CHANNEL CALIBRATION of the core exit thermocouples is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

REFERENCES

1. USAR Appendix 7A.
2. Regulatory Guide 1.97, Rev. 2, December 1980.
3. NUREG-0737, Supplement 1, "TMI Action Items."
4. USAR Figure 5.1-1 (sheet 4).
5. NA 94-0089 dated May 24, 1994.

BASES

ACTIONS

A.1 (continued)

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP DG start instrumentation channels are configured in LSELS to provide a one-out-of-three logic to initiate a trip of the incoming offsite power, shed ESF bus loads, and generate an LOP DG start signal.

A Note is added to allow bypassing an inoperable channel for up to 4 hours for surveillance testing of other channels. This allowance is made where bypassing the channel does not cause an actuation and where at least two other channels are monitoring that parameter.

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

B.1

Condition B applies when more than one loss of voltage or more than one degraded voltage channel per bus is inoperable. The associated LSELS must be declared inoperable immediately when:

a) More than one loss of voltage or more than one degraded voltage channel per bus is inoperable; or

b) The Required Action and associated completion Time of Condition A is not met.

Once in this Condition the affected instrument function (loss of voltage or degraded voltage) may no longer be single failure proof or may no longer be functional for the affected bus. In this case, operation in the MODE of Applicability must be limited. Condition B requires that the associated LSELS be immediately declared inoperable. This action is appropriate because the affected instrument channels (loss of voltage or degraded voltage) are inputs to the LSELS. LSELS relies on these input circuits to perform its required actuations (turbine driven AFW pump start via BOP ESFAS, motor driven AFW pumps start via the LSELS, and diesel generator via LSELS).

The Completion Time of Required Action F.2 in LCO 3.8.1, "AC Sources - Operating," should allow ample time to repair most failures during

BASES

ACTIONS

B.1 (continued)

MODES 1 - 4 and takes into account the low probability of an event requiring an LOP start occurring during this interval. When the associated DG is required to be OPERABLE in MODES 5 and 6, the Completion Time of Required Action C.1 in LCO 3.8.2, "AC Sources - Shutdown," is consistent with the required times for actions requiring prompt action.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

Not Used.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a TADOT. This test is performed every 31 days. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. For these tests, the relay Trip Setpoints are verified and adjusted as necessary. The SR is modified by a Note that excludes verification of time delays. Testing of the time delay relays is performed as part of the CHANNEL CALIBRATION (SR 3.3.5.3). The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience. If the measured setpoint does not exceed the Allowable Value, the trip device is considered OPERABLE.

SR 3.3.5.3

SR 3.3.5.3 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

Calculation XX-E-009 (Ref. 3) calculates the undervoltage/degraded voltage setpoints for the NB/NG relays. The calculation also ensures adequate voltage will be present at the end use loads under minimum switchyard voltage and maximum accident loading. Calculation XX-E-009 identifies that the minimum acceptable voltage for the NB01 bus is 3707 V (105.9 V after PT) and for the NB02 bus is 3704 V (105.9 V after PT).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.3 (continued)

The Frequency of 18 months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.4

SR 3.3.5.4 is the performance of the required response time verification every 18 months on a STAGGERED TEST BASIS. This SR measures the total response time of the undervoltage relays, logic circuitry and EDG start time. Response time verification acceptance criteria are:

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME
Loss of Power	
a. 4kV Bus Undervoltage - Loss of Voltage	≤ 14 seconds
b. 4kV Bus Undervoltage - Grid Degraded Voltage	≤ 144 seconds

Each verification shall include at least one train such that both trains are verified at least once per 36 months.

REFERENCES

1. USAR, Section 8.3.
2. USAR, Chapter 15.
3. Calculation XX-E-009, "System NB, NG, PG Undervoltage/Degraded Voltage Relay Setpoints."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

The function of the seal injection throttle valves (BG-V0198 through BG-V0201) during an accident is similar to the function of the ECCS throttle valves in that each restricts flow from the centrifugal charging pump header to the Reactor Coolant System (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during safety injection (SI).

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The LOCA analysis establishes the minimum flow for the ECCS pumps. The centrifugal charging pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head at the design point for the centrifugal charging pumps. The steam generator tube rupture and main steam line break event analyses also credit the centrifugal charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

The LCO ensures that seal injection flow will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the centrifugal charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory. Figure 3.5.5-1 was developed using a conservative combination of plant data to establish a maximum flow rate for the seal injection line versus delta pressure between the RCS and charging pump header pressure. Based on the conservative data, Figure 3.5.5-1 ensures adequate flow to the reactor coolant pump seals while ensuring the safety analysis assumption for minimum ECCS flow is maintained while avoiding charging pump runout conditions. This figure is constructed from the equation Q = $\sqrt{0.6661 * DP}$ where Q = seal injection

BASES

APPLICABLE SAFETY ANALYSIS (continued)

flow in gpm, and DP=charging pump discharge header minus RCS pressure in units of psid (Ref. 3). The constant inside the square root is a function of pipe size, throttle valve resistance (position) and fluid density. Seal injection flow satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The intent of the LCO limit on seal injection flow is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the injection points (Ref. 2).

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a pressure and flow must be known. The flow line resistance is established by adjusting the RCP seal injection throttle valves such that the analyzed ECCS flow to the RCP seals is limited to 90 gpm with once centrifugal charging pump operating at its runout condition. This accident analysis limit is met by positioning the valves so that the flow to the RCP seals is within the limits of Figure 3.5.5-1. The centrifugal charging pump discharge header pressure remains essentially constant through all the applicable MODES of this LCO. A reduction in RCS pressure would result in more flow being diverted to the RCP seal injection line than at normal operating pressure. The valve settings established at the prescribed centrifugal charging pump discharge header pressure result in a conservative valve position should RCS pressure decrease. The flow limits established by Figure 3.5.5-1 ensures that the minimum ECCS flow assumed in the safety analyses is maintained.

The limit on seal injection flow must be met to render the ECCS OPERABLE. If this condition is not met, the ECCS flow may be less than that assumed in the accident analyses.

APPLICABILITY

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower, however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in these MODES. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

ACTIONS

A.1

With the seal injection flow exceeding its limit, the amount of charging flow available to the RCS may be reduced. Under this Condition, action must

BASES

ACTIONS

A.1 (continued)

be taken to restore the flow to below its limit. The operator has 4 hours from the time the flow is known to be above the limit to correctly position the manual seal injection throttle valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is conservative with respect to the Completion Times of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.

B.1 and B.2

When the Required Actions cannot be completed within the required Completion Time, a controlled shutdown must be initiated. The Completion Time of 6 hours for reaching MODE 3 from MODE 1 is a reasonable time for a controlled shutdown, based on operating experience and normal cooldown rates, and does not challenge plant safety systems or operators. Continuing the plant shutdown begun in Required Action B.1, an additional 6 hours is a reasonable time, based on operating experience and normal cooldown rates, to reach MODE 4, where this LCO is no longer applicable.

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

Verification every 18 months that the manual seal injection throttle valves are adjusted to give a flow within the limit ensures that proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained. To verify acceptable seal injection flow, the following is performed; differential pressure between the charging header (PT-120) and the RCS is determined and the seal injection flow is verified to be within the limits of Figure 3.5.5-1. The Frequency of 18 months is based on engineering judgment, the controls placed on the positioning of these valves and is consistent with other ECCS valve Surveillance Frequencies in SR 3.5.2.7. The Frequency has proven to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1 (continued)

As noted, the Surveillance is not required to be performed until 4 hours after the RCS pressure has stabilized within a ± 20 psig range of normal operating pressure. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual valves are set correctly. The exception is limited to 4 hours to ensure that the Surveillance is timely.

REFERENCES

1. USAR, Chapter 6 and Chapter 15.
2. 10 CFR 50.46.
3. Calculation SA-91-016-0-000-CN001, "ECCS Design Basis Injection Flowrates Re-analysis in Supporting of the WCGS Power Re-Rating project."

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing or securing.

A Note has been added that allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position is small.

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. Isolation times are provided in USAR Figure 6.2.4-1 (Ref. 2). The Frequency of this SR is in accordance with the Inservice Testing Program. |

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.5 (continued)

The Inservice Testing Program uses ASME Code Case OMN-1, "Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light-Water Reactor Plants," in lieu of stroke time testing for motor operated valves (Ref. 7). The parameters that must be present to achieve the analyzed isolation time under design basis conditions are measured. This process verifies design basis capability, including isolation time, and is a significant improvement over simple stroke time measurement. The Frequency of this Surveillance is determined through a mix of risk informed and performance based means in accordance with the Inservice Testing Program.

SR 3.6.3.6

Leakage integrity tests with a maximum allowable leakage rate for containment shutdown purge supply and exhaust isolation valves will provide early indication of resilient material seal degradation and will allow opportunity for repair before gross leakage failures could develop.

This SR is modified by a Note indicting that the SR is only required to be performed when the containment shutdown purge valves blind flanges are installed.

If the blind flange is installed, leakage rate testing of the valve and its associated blind flange must be performed every 24 months and following each reinstallation of the blind flange. Operating experience has demonstrated that this testing frequency is adequate to assure this penetration is leak tight.

The combined leakage rate for the containment shutdown purge supply and exhaust isolation valves, when pressurized to P_a, and included with all Type B and C penetrations is less than .60 L_a.

SR 3.6.3.7

For containment mini-purge and shutdown purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. 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 Multi-Plant Action No. B-20, "Containment Leakage Due to Seal Deterioration" (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. Feedwater Line Break (FWLB);

b. Main Steam Line Break; and

c. Loss of MFW.

In addition, the minimum available AFW flow and system characteristics are considerations in the analysis of a small break loss of coolant accident (LOCA). The AFW System design is such that it can perform its function following an FWLB between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of one motor driven AFW pump. This results in minimum assumed flow to the intact steam generators. One motor driven AFW pump would deliver to the broken MFW header at a flow rate throttled by the motor operated "smart" discharge valve until the problem was detected, and flow terminated by the operator. Sufficient flow would be delivered to the intact steam generator by the residual flow from the affected pump plus the turbine driven AFW pump.

The BOP ESFAS automatically actuates the AFW turbine driven pump when required to ensure an adequate feedwater supply to the steam generators during loss of power. DC power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

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

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each capable of automatically transferring the suction from

BASES

LCO (continued)	the CST to an ESW supply and supplying AFW to two steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of automatically transferring the suction from the CST to an ESW supply and supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. The inoperability of a single supply line or a single suction isolation valve from an ESW train to the turbine driven AFW pump causes a loss of redundancy in ESW supply to the pump but does not render the turbine driven AFW train inoperable. The supply line begins at the point where the ESW piping branches into two lines, one supplying the motor driven AFW pump and one supplying the turbine driven AFW pump, and ends at the suction of the turbine driven AFW pump (Ref. 3). Therefore, with one ESW train inoperable, the associated motor driven AFW train is considered inoperable; and one turbine driven AFW pump supply line is considered inoperable. However, the turbine driven AFW train is OPERABLE based on the remaining OPERABLE ESW supply line. In order for the turbine driven AFW pump and motor driven AFW pumps to be OPERABLE while the AFW System is in automatic control or above 10% RTP, the discharge flow control valves shall be in the full open position. When ≤ 10% RTP, the turbine driven AFW pump and motor driven AFW pumps remain OPERABLE with the discharge flow control valves throttled as needed to maintain steam generator levels. The nitrogen accumulator tanks supplying the turbine driven AFW pump control valves and the steam generator atmospheric relief valves ensure an eight hour supply for the pump and valves. Although the AFW System may be used in MODE 4 to remove decay heat, the LCO does not require the AFW System to be OPERABLE in MODE 4 since the RHR System is available for decay heat removal.
APPLICABILITY	In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions. In MODE 4 the AFW System may be used for heat removal via the steam generators but is not required since the RHR System is available and required to be OPERABLE in this MODE.

B 3.7 PLANT SYSTEMS

B 3.7.16 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

In the High Density Rack (HDR) design (Refs. 1 and 2), each fuel pool storage rack location is designated as either Region 1, Region 2, Region 3, or empty (in the checkerboarding configuration). Numerous configurations of region designation are possible. Criteria are established for determining an acceptable configuration (Ref. 1). The HDRs will store a maximum of 2363 fuel assemblies in the spent fuel pool and potentially an additional 279 fuel assemblies in the cask loading pool with racks installed). Full-core offload capability will be maintained. The fuel storage pool consists of the spent fuel pool and the cask loading pool (with racks installed). Region 1 locations are designed to accommodate new fuel with a nominal maximum enrichment of 4.6 wt% U-235 with no integral fuel burnable absorber (IFBA); or up to a nominal maximum enrichment of 5.0 wt% U-235 with 16 IFBA (Ref. 2); or spent fuel regardless of the discharge fuel burnup. Region 2 and 3 locations are designed to accommodate fuel of various initial enrichments, which have accumulated minimum burnups within the acceptable domain according to Figure 3.7.17-1, in the accompanying LCO. Fuel assemblies not meeting the criteria of Figure 3.7.17-1 shall be stored in accordance with paragraph 4.3.1.1 in Section 4.3, Fuel Storage. Locations designated as empty cells shall contain no fuel assemblies.

The water in the fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the HDR design is based on the use of unborated water, which maintains the fuel storage pool in a subcritical condition during normal operation with the fuel storage pool racks fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the April 1978 NRC letter (Ref. 3) allows credit for soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. For example, the most severe accident scenario is associated with the accidental misloading of multiple fuel assemblies in non-Region 1 locations. This could potentially increase the reactivity of the fuel storage pool. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Safe operation of the HDR with no movement of assemblies may therefore be achieved by controlling the location of

BASES

BACKGROUND (continued)

each assembly in accordance with LCO 3.7.17, "Spent Fuel Assembly Storage." Prior to movement of an assembly, it is necessary to perform SR 3.7.16.1.

APPLICABLE SAFETY ANALYSES

Accidents can be postulated that could increase the reactivity of the fuel storage pool which are unacceptable with unborated water in the fuel storage pool. Thus, for these accident occurrences, the presence of soluble boron in the storage pool maintains subcriticality with a K_{eff} of 0.95 or less. The postulated accidents are basically of two types. Multiple fuel assemblies could be incorrectly transferred to non-Region 1 locations (e.g., unirradiated fuel assemblies or insufficiently depleted fuel assemblies). The second type of postulated accidents is associated with a fuel assembly which is dropped adjacent to the fully loaded storage rack. The negative reactivity effect of the soluble boron compensates for the increased reactivity caused by either one of the two postulated accident scenarios. The accident analyses is provided in the USAR, Appendix 9.1A (Ref. 1).

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The fuel storage pool boron concentration is required to be = 2165 ppm. The fuel storage pool consists of the spent fuel pool and cask loading pool (with racks installed). The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential critical accident scenarios as described in Reference 1. This concentration of dissolved boron is the minimum required concentration for non-inventoried fuel assembly storage and movement within the fuel storage pool.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the fuel storage pool, until a complete fuel storage pool verification has been performed following the last movement of fuel assemblies in the fuel storage pool. This verification shall consist of a confirmation of the fuel assembly serial number of every assembly moved in the fuel storage pool since the last verification. This LCO does not apply following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for misloaded fuel assemblies or a dropped fuel assembly.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil temperature are being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions using one of the following signals and achieves required voltage and frequency within 12 seconds, and subsequently achieves steady state required voltage and frequency ranges:

a. Manual, or
b. Simulated loss of offsite power by itself, or
c. Safety Injection test signal.

The 12 second start requirement supports the assumptions of the design basis LOCA analysis in the USAR, Chapter 15 (Ref. 5).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The 12 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, the 12 second start requirement of SR 3.8.1.7 applies.

A minimum voltage and frequency is specified rather than an upper and lower limit because DG acceleration 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 12 seconds, and result in a failure of the SR. However, on an actual emergency start, the DG would reach minimum voltage and frequency in ≤ 12 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 DG to satisfy the requirements without including a potential for failing the Surveillance.

While reaching minimum voltage and frequency (at which the DG can accept load) in ≤ 12 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 for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance. This additional monitoring and trending is part of the TR 5.5.2, "Emergency Diesel Generator Reliability Program" and is not considered part of the SR. (Reference 14)

Since SR 3.8.1.7 requires a 12 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 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 greater than or equal to the equivalent of the maximum expected accident loads and aligned to

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

provide standby power to the associated emergency buses. 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 DG shall be operated continuously for the 60 minute time period per the guidance of Regulatory Guide 1.9, Position 2.2.2 (Ref. 3).

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 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. Momentary power factor transients outside the normal range are acceptable during this surveillance since no power factor requirements are established by this SR. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that, with the DG in a standby condition, the fuel oil transfer pump starts on low level in the day tank standpipe and shuts down on high level in the day tank standpipe to automatically maintain the day tank fuel oil level above the DG fuel headers. The fuel oil standpipe must have adequate level to keep the fuel oil supply header to the engine injector pumps full, so that the engine can meet the required 12 second start time. The minimum fuel oil free surface elevation is required to be at least 86 inches from the bottom (outside diameter) of the tank. The transfer pump start/stop setpoints are controlled to maintain level in the standpipe in order to ensure there is sufficient fuel to meet the 12 second start requirement for the DG. This level also ensures adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility 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 31 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 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. 10). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

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

The Frequency for this SR is 31 days.

Periodically, the capability of the fuel oil transfer pump to supply the opposite train DG via the installed cross-connect line is verified.

SR 3.8.1.7

See SR 3.8.1.2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

Not Used.

SR 3.8.1.9

Not Used.

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 testsimulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and 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.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≥ 0.8 and ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9, Rev. 3 (Ref. 3), and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), this Surveillance demonstrates the as-designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The DG autostart time of 12 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or residual heat removal (RHR)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 systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (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 two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

The Note 2 restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum,

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (12 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the 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, ECCS injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or RHR 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.

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

The Note 2 restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the 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 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9, Rev. 3, (Ref. 3), 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 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG (Refer to discussion of Note 3 below). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor of ≥ 0.8 and ≤ 0.9 at a voltage of 4160 +160 -420 volts and a frequency of 60 ± 1.2 Hz. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience. 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.

Administrative controls for performing this SR in MODES 1 or 2, with the DG connected to an offsite circuit, ensure or require that:

a. Weather conditions are conducive for performing this SR.

b. The offsite power supply and switchyard conditions are conducive for performing this SR, which includes ensuring that switchyard access is restricted and no elective maintenance within the switchyard is performed.

c. No equipment or systems assumed to be available for supporting the performance of the SR are removed from service.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients outside the power factor range will not invalidate the test. Note 2 permits the elimination of the 2-hour overload test, provided that the combined emergency loads on a DG do not exceed its continuous duty rating.

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 12 seconds. The 12 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, Rev. 3 (Ref. 3).

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.9, Rev. 3 (Ref. 3), this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive a close 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, Rev. 3 (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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

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

SR 3.8.1.17

Demonstration of the test mode (parallel 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 Safety Injection actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

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, Rev. 3 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. The restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the 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 or 2. 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 LSELS. 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 10% load sequence time interval 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. Reference 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, Rev. 3 (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.

The 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

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, Rev. 0, January 1978.
11. ANSI C84.1-1982.
12. IEEE Standard 308-1978.
13. Configuration Change Package (CCP) 08052, Revision 1, April 23, 1999.
14. Amendment No. 161, April 21, 2005.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1.

SR 3.9.3.2

SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The source range neutron detectors are maintained based on manufacturer's recommendations. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13, GDC 26, GDC 28, and GDC 29.

2. NRC letter (J. Stone to O. Maynard) dated October 3, 1997: "Wolf Creek Generating Station - Technical Specification Bases Change, Source Range Nuclear Instruments Power Supply Requirements."

B 3.9 REFUELING OPERATIONS

B 3.9.4 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment penetration closure" rather than "containment OPERABILITY." Containment penetration closure means that all potential escape paths are closed or capable of being closed within 2 hours. Since there is no potential for containment pressurization, the 10 CFR 50, Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 100. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. If closed, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced. The equipment hatch may be open during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, provided it can be installed with a minimum of four bolts holding it in place. During shutdown conditions, adequate missile protection for safety related equipment in containment is provided with the equipment hatch held in place with 6 bolts. Administrative controls ensure the equipment hatch is in place during the threat of severe weather that could result in the generation of tornado driven missiles. (Ref. 5).

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during

BASES

BACKGROUND (continued)

MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment penetration closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment penetration closure is required; however, the door interlock mechanism may remain disabled provided one personnel air lock door is capable of being closed and one emergency air lock door is closed. In the case of the emergency air lock door, a temporary closure device is an acceptable replacement for the air lock door (Ref. 1).

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling.

The Containment Purge System includes two subsystems. The shutdown purge subsystem includes a 36 inch supply penetration and a 36 inch exhaust penetration. The second subsystem, a mini-purge system, includes an 18 inch supply penetration and an 18 inch exhaust penetration. During MODES 1, 2, 3, and 4, the two valves in each of the shutdown purge supply and exhaust penetrations are secured in the closed position or blind flange installed. The two valves in each of the two minipurge penetrations can be opened intermittently, but are closed automatically by the Engineered Safety Features Actuation System (ESFAS). Neither of the subsystems is subject to a Specification in MODE 5 or MODE 6 excluding CORE ALTERATIONS or movement of irradiated fuel in containment.

In MODE 6, large air exchanges are necessary to conduct refueling operations. The normal 36 inch purge system is used for this purpose, and all four valves may be closed by the ESFAS in accordance with LCO 3.3.6, "Containment Purge Isolation Instrumentation," during CORE ALTERATIONS or movement of irradiated fuel in containment.

When the minipurge system is not used in MODE 6, all four 18 inch valves are closed.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at

BASES

BACKGROUND (continued)

least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations and the emergency personnel escape lock during fuel movements (Ref. 1).

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 2). Fuel handling accident, analyzed in Reference 2, assumes dropping a single irradiated fuel assembly. The time to close containment penetrations under administrative controls is assumed to be not more than a 2 hour period, consistent with the 2 hour period of release assumed in the accident analysis (Ref. 6). The requirements of LCO 3.9.7, "Refueling Pool Water Level," and the minimum decay time of 100 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the guideline values specified in 10 CFR 100. Standard Review Plan, Section 15.7.4, Rev. 1 (Ref. 3), defines "well within" 10 CFR 100 to be 25% or less of the 10 CFR 100 values. The acceptance limits for offsite radiation exposure will be 25% of 10 CFR 100 values.

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge penetrations, the personnel airlock, and the equipment hatch (which must be capable of being closed). For the OPERABLE containment purge penetrations, this LCO ensures that each penetration is isolable by the Containment Purge Isolation System to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

One door in the emergency air lock must be closed and one door in the personnel air lock must be capable of being closed. Both containment personnel air lock doors may be open during movement of irradiated fuel or CORE ALTERATIONS, provided an air lock door is capable of being closed and the water level in the refueling pool is maintained as required. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the containment during movement of

BASES

LCO (continued)

irradiated fuel or CORE ALTERATIONS, 2) specified individuals are designated and readily available to close the air lock following an evacuation that would occur in the event of a fuel handling accident, and 3) any obstructions (e.g., cables and hoses) that would prevent rapid closure of an open air lock can be quickly removed (Ref. 4). LCO 3.9.4.b is modified by a Note allowing an emergency escape air lock temporary closure device to be an acceptable replacement for an emergency air lock door.

The equipment hatch may be open during movement of irradiated fuel or CORE ALTERATIONS provided the hatch is capable of being closed and the water level in the refueling pool is maintained as required. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the containment during movement of irradiated fuel or CORE ALTERATIONS, 2) specified individuals are designated and readily available to close the equipment hatch following an evacuation that would occur in the event of a fuel handling accident, and 3) any obstructions (e.g., cables and hoses) that would prevent rapid closure of the equipment hatch can be quickly removed.

The LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path within 2 hours in the event of a fuel handling accident.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

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

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status,

BASES

ACTIONS

A.1 and A.2 (continued)

including the containment purge isolation valve not capable of automatic actuation, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge isolation valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge isolation signal. Containment penetrations that are open under administrative controls are not required to meet the SR during the time the penetrations are open.

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. A surveillance before the start of refueling operations will provide sufficient surveillance verification during the applicable period for this LCO. As such, this Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in a release of fission product radioactivity to the outside atmosphere.

SR 3.9.4.2

This Surveillance demonstrates that the necessary hardware, tools, and equipment are available to install the equipment hatch. The equipment hatch is provided with a set of hardware, tools, and equipment for moving the hatch from its storage location and installing it in the opening. The required set of hardware, tools, and equipment shall be inspected to ensure that they can perform the required functions.

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment. The Surveillance interval is selected to be commensurate

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SURVEILLANCE REQUIREMENTS

SR 3.9.4.2 (continued)

with the normal duration of time to complete the fuel handling operations. The Surveillance is modified by a Note which only requires that the Surveillance be met for an open equipment hatch. If the equipment hatch is installed in its opening, the availability of the means to install the hatch is not required. The 7 day Frequency is adequate considering that the hardware, tools, and equipment are dedicated to the equipment hatch and not used for any other function.

SR 3.9.4.3

This Surveillance demonstrates that each containment purge isolation valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. The 18 month Frequency maintains consistency with other similar ESFAS instrumentation and valve testing requirements. In LCO 3.3.6, the Containment Purge Isolation instrumentation requires a CHANNEL CHECK every 12 hours and a COT every 92 days to ensure the channel OPERABILITY during refueling operations. Every 18 months a CHANNEL CALIBRATION is performed. SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements. These Surveillances will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

REFERENCES

1. Amendment No. 74 to Wolf Creek Generating Station Operating License NPF-42, dated July 7, 1994.
2. USAR, Section 15.7.4.
3. NUREG-0800, Section 15.7.4, Rev. 1, July 1981.
4. Amendment No. 95 to Wolf Creek Generating Station Operating License NPF-42, dated February 28, 1996.
5. Configuration Change Package 7784.
6. Amendment No. 135 to Wolf Creek Generating Station Operating License NPF-42, dated September 12, 2000.

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iii	2	DRR 00-0147	4/24/00
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B 2.1.1-3	14	DRR 03-0102	2/12/03
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B 2.1.2-2	12	DRR 02-1062	9/26/02
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B 3.0-7	19	DRR 04-1414	10/12/04
B 3.0-8	19	DRR 04-1414	10/12/04
B 3.0-9	19	DRR 04-1414	10/12/04
B 3.0-10	19	DRR 04-1414	10/12/04
B 3.0-11	19	DRR 04-1414	10/12/04
B 3.0-12	19	DRR 04-1414	10/12/04
B 3.0-13	19	DRR 04-1414	10/12/04
B 3.0-14	19	DRR 04-1414	10/12/04
B 3.0-15	19	DRR 04-1414	10/12/04
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B 3.1.1-5	0	Amend. No. 123	12/18/99
B 3.1.2-1	0	Amend. No. 123	12/18/99
B 3.1.2-2	0	Amend. No. 123	12/18/99
B 3.1.2-3	0	Amend. No. 123	12/18/99
B 3.1.2-4	0	Amend. No. 123	12/18/99
B 3.1.2-5	0	Amend. No. 123	12/18/99
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B 3.1.8-1	0	Amend. No. 123	12/18/99
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B 3.1.8-4	15	DRR 03-0860	7/10/03
B 3.1.8-5	0	Amend. No. 123	12/18/99
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B 3.2.1-4	0	Amend. No. 123	12/18/99
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B 3.2.1-7	0	Amend. No. 123	12/18/99
B 3.2.1-8	0	Amend. No. 123	12/18/99
B 3.2.1-9	4	DRR 00-1365	9/28/00
B 3.2.2-1	0	Amend. No. 123	12/18/99
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B 3.3.2-56	20	DRR 04-1533	2/16/05
B 3.3.2-57	20	DRR 04-1533	2/16/05
B 3.3.2-58	20	DRR 04-1533	2/16/05
B 3.3.3-1	0	Amend. No. 123	12/18/99
B 3.3.3-2	5	DRR 00-1427	10/12/00
B 3.3.3-3	0	Amend. No. 123	12/18/99
B 3.3.3-4	0	Amend. No. 123	12/18/99
B 3.3.3-5	0	Amend. No. 123	12/18/99
B 3.3.3-6	8	DRR 01-1235	9/19/01
B 3.3.3-7	21	DRR 05-0707	4/20/05
B 3.3.3-8	8	DRR 01-1235	9/19/01
B 3.3.3-9	8	DRR 01-1235	9/19/01
B 3.3.3-10	19	DRR 04-1414	10/12/04
B 3.3.3-11	19	DRR 04-1414	10/12/04
B 3.3.3-12	21	DRR 05-0707	4/20/05
B 3.3.3-13	21	DRR 05-0707	4/20/05
B 3.3.3-14	8	DRR 01-1235	9/19/01
B 3.3.3-15	8	DRR 01-1235	9/19/01
B 3.3.4-1	0	Amend. No. 123	12/18/99
B 3.3.4-2	9	DRR 02-1023	2/28/02
B 3.3.4-3	15	DRR 03-0860	7/10/03
B 3.3.4-4	19	DRR 04-1414	10/12/04
B 3.3.4-5	1	DRR 99-1624	12/18/99
B 3.3.4-6	9	DRR 02-0123	2/28/02
B 3.3.5-1	0	Amend. No. 123	12/18/99
B 3.3.5-2	1	DRR 99-1624	12/18/99
B 3.3.5-3	1	DRR 99-1624	12/18/99
B 3.3.5-4	1	DRR 99-1624	12/18/99
B 3.3.5-5	0	Amend. No. 123	12/18/99

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TAB – B 3.3 INSTRUMENTATION (continued)			
B 3.3.5-6	22	DRR 05-1375	6/28/05
B 3.3.5-7	22	DRR 05-1375	6/28/05
B 3.3.6-1	0	Amend. No. 123	12/18/99
B 3.3.6-2	0	Amend. No. 123	12/18/99
B 3.3.6-3	0	Amend. No. 123	12/18/99
B 3.3.6-4	0	Amend. No. 123	12/18/99
B 3.3.6-5	0	Amend. No. 123	12/18/99
B 3.3.6-6	0	Amend. No. 123	12/18/99
B 3.3.6-7	0	Amend. No. 123	12/18/99
B 3.3.7-1	0	Amend. No. 123	12/18/99
B 3.3.7-2	0	Amend. No. 123	12/18/99
B 3.3.7-3	0	Amend. No. 123	12/18/99
B 3.3.7-4	0	Amend. No. 123	12/18/99
B 3.3.7-5	0	Amend. No. 123	12/18/99
B 3.3.7-6	0	Amend. No. 123	12/18/99
B 3.3.7-7	0	Amend. No. 123	12/18/99
B 3.3.7-8	0	Amend. No. 123	12/18/99
B 3.3.8-1	0	Amend. No. 123	12/18/99
B 3.3.8-2	0	Amend. No. 123	12/18/99
B 3.3.8-3	0	Amend. No. 123	12/18/99
B 3.3.8-4	0	Amend. No. 123	12/18/99
B 3.3.8-5	0	Amend. No. 123	12/18/99
B 3.3.8-6	0	Amend. No. 123	12/18/99
B 3.3.8-7	0	Amend. No. 123	12/18/99
TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS)			
B 3.4.1-1	0	Amend. No. 123	12/18/99
B 3.4.1-2	10	DRR 02-0411	4/5/02
B 3.4.1-3	10	DRR 02-0411	4/5/02
B 3.4.1-4	0	Amend. No. 123	12/18/99
B 3.4.1-5	0	Amend. No. 123	12/18/99
B 3.4.1-6	0	Amend. No. 123	12/18/99
B 3.4.2-1	0	Amend. No. 123	12/18/99
B 3.4.2-2	0	Amend. No. 123	12/18/99
B 3.4.2-3	0	Amend. No. 123	12/18/99
B 3.4.3-1	0	Amend. No. 123	12/18/99
B 3.4.3-2	0	Amend. No. 123	12/18/99
B 3.4.3-3	0	Amend. No. 123	12/18/99
B 3.4.3-4	0	Amend. No. 123	12/18/99
B 3.4.3-5	0	Amend. No. 123	12/18/99
B 3.4.3-6	0	Amend. No. 123	12/18/99
B 3.4.3-7	0	Amend. No. 123	12/18/99
B 3.4.4-1	0	Amend. No. 123	12/18/99
B 3.4.4-2	0	Amend. No. 123	12/18/99
B 3.4.4-3	0	Amend. No. 123	12/18/99
B 3.4.5-1	0	Amend. No. 123	12/18/99
B 3.4.5-2	17	DRR 04-0453	5/26/04
B 3.4.5-3	12	DRR 02-1062	9/26/02
B 3.4.5-4	0	Amend. No. 123	12/18/99
B 3.4.5-5	12	DRR 02-1062	9/26/02

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TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)			
B 3.4.6-1	17	DRR 04-0453	5/26/04
B 3.4.6-2	12	DRR 02-1062	9/26/02
B 3.4.6-3	12	DRR 02-1062	9/26/02
B 3.4.6-4	12	DRR 02-1062	9/26/02
B 3.4.6-5	12	DRR 02-1062	9/26/02
B 3.4.7-1	12	DRR 02-1062	9/26/02
B 3.4.7-2	17	DRR 04-0453	5/26/04
B 3.4.7-3	0	Amend. No. 123	12/18/99
B 3.4.7-4	12	DRR 02-1062	9/26/02
B 3.4.7-5	12	DRR 02-1062	9/26/02
B 3.4.8-1	17	DRR 04-0453	5/26/04
B 3.4.8-2	19	DRR 04-1414	10/12/04
B 3.4.8-3	12	DRR 02-1062	9/26/02
B 3.4.8-4	12	DRR 02-1062	9/26/02
B 3.4.9-1	0	Amend. No. 123	12/18/99
B 3.4.9-2	0	Amend. No. 123	12/18/99
B 3.4.9-3	0	Amend. No. 123	12/18/99
B 3.4.9-4	0	Amend. No. 123	12/18/99
B 3.4.10-1	5	DRR 00-1427	10/12/00
B 3.4.10-2	5	DRR 00-1427	10/12/00
B 3.4.10-3	0	Amend. No. 123	12/18/99
B 3.4.10-4	5	DRR 00-1427	10/12/00
B 3.4.11-1	0	Amend. No. 123	12/18/99
B 3.4.11-2	1	DRR 99-1624	12/18/99
B 3.4.11-3	19	DRR 04-1414	10/12/04
B 3.4.11-4	0	Amend. No. 123	12/18/99
B 3.4.11-5	1	DRR 99-1624	12/18/99
B 3.4.11-6	0	Amend. No. 123	12/18/99
B 3.4.11-7	0	Amend. No. 123	12/18/99
B 3.4.12-1	1	DRR 99-1624	12/18/99
B 3.4.12-2	1	DRR 99-1624	12/18/99
B 3.4.12-3	0	Amend. No. 123	12/18/99
B 3.4.12-4	1	DRR 99-1624	12/18/99
B 3.4.12-5	1	DRR 99-1624	12/18/99
B 3.4.12-6	1	DRR 99-1624	12/18/99
B 3.4.12-7	0	Amend. No. 123	12/18/99
B 3.4.12-8	1	DRR 99-1624	12/18/99
B 3.4.12-9	19	DRR 04-1414	10/12/04
B 3.4.12-10	0	Amend. No. 123	12/18/99
B 3.4.12-11	0	Amend. No. 123	12/18/99
B 3.4.12-12	0	Amend. No. 123	12/18/99
B 3.4.12-13	0	Amend. No. 123	12/18/99
B 3.4.12-14	0	Amend. No. 123	12/18/99
B 3.4.13-1	0	Amend. No. 123	12/18/99
B 3.4.13-2	0	Amend. No. 123	12/18/99
B 3.4.13-3	0	Amend. No. 123	12/18/99
B 3.4.13-4	0	Amend. No. 123	12/18/99
B 3.4.13-5	12	DRR 02-1062	9/26/02
B 3.4.13-6	0	Amend. No. 123	12/18/99
B 3.4.14-1	0	Amend. No. 123	12/18/99
B 3.4.14-2	0	Amend. No. 123	12/18/99

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TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS) *(continued)*			
B 3.4.14-3	0	Amend. No. 123	12/18/99
B 3.4.14-4	0	Amend. No. 123	12/18/99
B 3.4.14-5	16	DRR 03-1497	11/4/03
B 3.4.14-6	16	DRR 03-1497	11/4/03
B 3.4.15-1	2	DRR 00-0147	4/24/00
B 3.4.15-2	0	Amend. No. 123	12/18/00
B 3.4.15-3	9	DRR 02-0123	2/28/02
B 3.4.15-4	19	DRR 04-1414	10/12/04
B 3.4.15-5	9	DRR 02-1023	2/28/02
B 3.4.15-6	0	Amend. No. 123	12/18/99
B 3.4.15-7	0	Amend. No. 123	12/18/99
B 3.4.16-1	0	Amend. No. 123	12/18/99
B 3.4.16-2	1	DRR 99-1624	12/18/99
B 3.4.16-3	0	Amend. No. 123	12/18/99
B 3.4.16-4	19	DRR 04-1414	10/12/04
B 3.4.16-5	0	Amend. No. 123	12/18/99
B 3.4.16-6	0	Amend. No. 123	12/18/99
TAB – B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)			
B 3.5.1-1	0	Amend. No. 123	12/18/99
B 3.5.1-2	0	Amend. No. 123	12/18/99
B 3.5.1-3	0	Amend. No. 123	12/18/99
B 3.5.1-4	0	Amend. No. 123	12/18/99
B 3.5.1-5	1	DRR 99-1624	12/18/99
B 3.5.1-6	1	DRR 99-1624	12/18/99
B 3.5.1-7	16	DRR 03-1497	11/4/03
B 3.5.1-8	1	DRR 99-1624	12/18/99
B 3.5.2-1	0	Amend. No. 123	12/18/99
B 3.5.2-2	0	Amend. No. 123	12/18/99
B 3.5.2-3	0	Amend. No. 123	12/18/99
B 3.5.2-4	0	Amend. No. 123	12/18/99
B 3.5.2-5	0	Amend. No. 123	12/18/99
B 3.5.2-6	0	Amend. No. 123	12/18/99
B 3.5.2-7	0	Amend. No. 123	12/18/99
B 3.5.2-8	0	Amend. No. 123	12/18/99
B 3.5.2-9	12	DRR 02-1062	9/26/02
B 3.5.2-10	0	Amend. No. 123	12/18/99
B 3.5.3-1	16	DRR 03-1497	11/4/03
B 3.5.3-2	19	DRR 04-1414	10/12/04
B 3.5.3-3	19	DRR 04-1414	10/12/04
B 3.5.3-4	16	DRR 03-1497	11/4/03
B 3.5.4-1	0	Amend. No. 123	12/18/99
B 3.5.4-2	0	Amend. No. 123	12/18/99
B 3.5.4-3	0	Amend. No. 123	12/18/99
B 3.5.4-4	0	Amend. No. 123	12/18/99
B 3.5.4-5	0	Amend. No. 123	12/18/99
B 3.5.4-6	0	Amend. No. 123	12/18/99
B 3.5.5-1	21	DRR 05-0707	4/20/05
B 3.5.5-2	21	DRR 05-0707	4/20/05
B 3.5.5-3	2	Amend. No. 132	4/24/00
B 3.5.5-4	21	DRR 05-0707	4/20/05

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TAB – B 3.6 CONTAINMENT SYSTEMS			
B 3.6.1-1	0	Amend. No. 123	12/18/99
B 3.6.1-2	0	Amend. No. 123	12/18/99
B 3.6.1-3	0	Amend. No. 123	12/18/99
B 3.6.1-4	17	DRR 04-0453	5/26/04
B 3.6.2-1	0	Amend. No. 123	12/18/99
B 3.6.2-2	0	Amend. No. 123	12/18/99
B 3.6.2-3	0	Amend. No. 123	12/18/99
B 3.6.2-4	0	Amend. No. 123	12/18/99
B 3.6.2-5	0	Amend. No. 123	12/18/99
B 3.6.2-6	0	Amend. No. 123	12/18/99
B 3.6.2-7	0	Amend. No. 123	12/18/99
B 3.6.3-1	0	Amend. No. 123	12/18/99
B 3.6.3-2	0	Amend. No. 123	12/18/99
B 3.6.3-3	0	Amend. No. 123	12/18/99
B 3.6.3-4	0	Amend. No. 123	12/18/99
B 3.6.3-5	8	DRR 01-1235	9/19/01
B 3.6.3-6	8	DRR 01-1235	9/19/01
B 3.6.3-7	8	DRR 01-1235	9/19/01
B 3.6.3-8	8	DRR 01-1235	9/19/01
B 3.6.3-9	8	DRR 01-1235	9/19/01
B 3.6.3-10	8	DRR 01-1235	9/19/01
B 3.6.3-11	9	DRR 02-0123	2/28/02
B 3.6.3-12	20	DRR 04-1533	2/16/05
B 3.6.3-13	9	DRR 02-0123	2/28/02
B 3.6.3-14	9	DRR 02-0123	2/28/02
B 3.6.4-1	2	DRR 00-0147	4/24/00
B 3.6.4-2	0	Amend. No. 123	12/18/99
B 3.6.4-3	0	Amend. No. 123	12/18/99
B 3.6.5-1	0	Amend. No. 123	12/18/99
B 3.6.5-2	0	Amend. No. 123	12/18/99
B 3.6.5-3	13	DRR 02-1458	12/03/02
B 3.6.5-4	0	Amend. No. 123	12/18/99
B 3.6.6-1	0	Amend. No. 123	12/18/99
B 3.6.6-2	0	Amend. No. 123	12/18/99
B 3.6.6-3	1	DRR 99-1624	12/18/99
B 3.6.6-4	0	Amend. No. 123	12/18/99
B 3.6.6-5	0	Amend. No. 123	12/18/99
B 3.6.6-6	18	DRR 04-1018	9/1/04
B 3.6.6-7	0	Amend. No. 123	12/18/99
B 3.6.6-8	14	DRR 03-0102	2/12/03
B 3.6.6-9	13	DRR 02-1458	12/03/02
B 3.6.7-1	0	Amend. No. 123	12/18/99
B 3.6.7-2	0	Amend. No. 123	12/18/99
B 3.6.7-3	0	Amend. No. 123	12/18/99
B 3.6.7-4	2	DRR 00-0147	4/24/00
B 3.6.7-5	0	Amend. No. 123	12/18/99
B 3.6.8-1	0	Amend. No. 123	12/18/99
B 3.6.8-2	0	Amend. No. 123	12/18/99
B 3.6.8-3	19	DRR 04-1414	10/12/04
B 3.6.8-4	0	Amend. No. 123	12/18/99
B 3.6.8-5	0	Amend. No. 123	12/18/99

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TAB – B 3.7 PLANT SYSTEMS			
B 3.7.1-1	0	Amend. No. 123	12/18/99
B 3.7.1-2	0	Amend. No. 123	12/18/99
B 3.7.1-3	0	Amend. No. 123	12/18/99
B 3.7.1-4	0	Amend. No. 123	12/18/99
B 3.7.1-5	0	Amend. No. 123	12/18/99
B 3.7.1-6	0	Amend. No. 123	12/18/99
B 3.7.2-1	0	Amend. No. 123	12/18/99
B 3.7.2-2	0	Amend. No. 123	12/18/99
B 3.7.2-3	0	Amend. No. 123	12/18/99
B 3.7.2-4	0	Amend. No. 123	12/18/99
B 3.7.2-5	0	Amend. No. 123	12/18/99
B 3.7.2-6	0	Amend. No. 123	12/18/99
B 3.7.3-1	0	Amend. No. 123	12/18/99
B 3.7.3-2	0	Amend. No. 123	12/18/99
B 3.7.3-3	0	Amend. No. 123	12/18/99
B 3.7.3-4	0	Amend. No. 123	12/18/99
B 3.7.3-5	0	Amend. No. 123	12/18/99
B 3.7.4-1	1	DRR 99-1624	12/18/99
B 3.7.4-2	1	DRR 99-1624	12/18/99
B 3.7.4-3	19	DRR 04-1414	10/12/04
B 3.7.4-4	19	DRR 04-1414	10/12/04
B 3.7.4-5	1	DRR 99-1624	12/18/99
B 3.7.5-1	0	Amend. No. 123	12/18/99
B 3.7.5-2	0	Amend. No. 123	12/18/99
B 3.7.5-3	0	Amend. No. 123	12/18/99
B 3.7.5-4	23	DRR 05-1995	9/28/05
B 3.7.5-5	19	DRR 04-1414	10/12/04
B 3.7.5-6	19	DRR 04-1414	10/12/04
B 3.7.5-7	19	DRR 04-1414	10/12/04
B 3.7.5-8	14	DRR 03-0102	2/12/03
B 3.7.5-9	13	DRR 02-1458	12/03/02
B 3.7.6-1	0	Amend. No. 123	12/18/99
B 3.7.6-2	0	Amend. No. 123	12/18/99
B 3.7.6-3	0	Amend. No. 123	12/18/99
B 3.7.7-1	0	Amend. No. 123	12/18/99
B 3.7.7-2	0	Amend. No. 123	12/18/99
B 3.7.7-3	0	Amend. No. 123	12/18/99
B 3.7.7-4	1	DRR 99-1624	12/18/99
B 3.7.8-1	0	Amend. No. 123	12/18/99
B 3.7.8-2	0	Amend. No. 123	12/18/99
B 3.7.8-3	0	Amend. No. 123	12/18/99
B 3.7.8-4	0	Amend. No. 123	12/18/99
B 3.7.8-5	0	Amend. No. 123	12/18/99
B 3.7.9-1	3	Amend. No. 134	7/14/00
B 3.7.9-2	3	Amend. No. 134	7/14/00
B 3.7.9-3	3	Amend. No. 134	7/14/00
B 3.7.9-4	3	Amend. No. 134	7/14/00
B 3.7.10-1	0	Amend. No. 123	12/18/99
B 3.7.10-2	15	DRR 03-0860	7/10/03
B 3.7.10-3	0	Amend. No. 123	12/18/99
B 3.7.10-4	0	Amend. No. 123	12/18/99

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TAB – B 3.7 PLANT SYSTEMS (continued)			
B 3.7.10-5	0	Amend. No. 123	12/18/99
B 3.7.10-6	0	Amend. No. 123	12/18/99
B 3.7.10-7	0	Amend. No. 123	12/18/99
B 3.7.11-1	0	Amend. No. 123	12/18/99
B 3.7.11-2	0	Amend. No. 123	12/18/99
B 3.7.11-3	0	Amend. No. 123	12/18/99
B 3.7.11-4	0	Amend. No. 123	12/18/99
B 3.7.12-1	0	Amend. No. 123	12/18/99
B 3.7.13-1	1	DRR 99-1624	12/18/99
B 3.7.13-2	1	DRR 99-1624	12/18/99
B 3.7.13-3	1	DRR 99-1624	12/18/99
B 3.7.13-4	1	DRR 99-1624	12/18/99
B 3.7.13-5	1	DRR 99-1624	12/18/99
B 3.7.13-6	12	DRR 02-1062	9/26/02
B 3.7.13-7	1	DRR 99-1624	12/18/99
B 3.7.13-8	1	DRR 99-1624	12/18/99
B 3.7.14-1	0	Amend. No. 123	12/18/99
B 3.7.15-1	0	Amend. No. 123	12/18/99
B 3.7.15-2	0	Amend. No. 123	12/18/99
B 3.7.15-3	0	Amend. No. 123	12/18/99
B 3.7.16-1	5	DRR 00-1427	10/12/00
B 3.7.16-2	23	DRR 05-1995	9/28/05
B 3.7.16-3	5	DRR 00-1427	10/12/00
B 3.7.17-1	7	DRR 01-0474	5/1/01
B 3.7.17-2	7	DRR 01-0474	5/1/01
B 3.7.17-3	5	DRR 00-1427	10/12/00
B 3.7.18-1	0	Amend. No. 123	12/18/99
B 3.7.18-2	0	Amend. No. 123	12/18/99
B 3.7.18-3	0	Amend. No. 123	12/18/99
TAB – B 3.8 ELECTRICAL POWER SYSTEMS			
B 3.8.1-1	0	Amend. No. 123	12/18/99
B 3.8.1-2	0	Amend. No. 123	12/18/99
B 3.8.1-3	6	DRR 00-1541	3/13/01
B 3.8.1-4	19	DRR 04-1414	10/12/04
B 3.8.1-5	19	DRR 04-1414	10/12/04
B 3.8.1-6	0	Amend. No. 123	12/18/99
B 3.8.1-7	0	Amend. No. 123	12/18/99
B 3.8.1-8	0	Amend. No. 123	12/18/99
B 3.8.1-9	0	Amend. No. 123	12/18/99
B 3.8.1-10	0	Amend. No. 123	12/18/99
B 3.8.1-11	0	Amend. No. 123	12/18/99
B 3.8.1-12	0	Amend. No. 123	12/18/99
B 3.8.1-13	0	Amend. No. 123	12/18/99
B 3.8.1-14	0	Amend. No. 123	12/18/99
B 3.8.1-15	22	DRR 05-1375	6/28/05
B 3.8.1-16	22	DRR 05-1375	6/28/05
B 3.8.1-17	22	DRR 05-1375	6/28/05
B 3.8.1-18	22	DRR 05-1375	6/28/05
B 3.8.1-19	22	DRR 05-1375	6/28/05
B 3.8.1-20	22	DRR 05-1375	6/28/05

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TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.1-21	22	DRR 05-1375	6/28/05
B 3.8.1-22	22	DRR 05-1375	6/28/05
B 3.8.1-23	22	DRR 05-1375	6/28/05
B 3.8.1-24	22	DRR 05-1375	6/28/05
B 3.8.1-25	22	DRR 05-1375	6/28/05
B 3.8.1-26	22	DRR 05-1375	6/28/05
B 3.8.1-27	18	DRR 04-1018	9/1/04
B 3.8.1-28	18	DRR 04-1018	9/1/04
B 3.8.1-29	22	DRR 05-1375	6/28/05
B 3.8.2-1	0	Amend. No. 123	12/18/99
B 3.8.2-2	0	Amend. No. 123	12/18/99
B 3.8.2-3	0	Amend. No. 123	12/18/99
B 3.8.2-4	0	Amend. No. 123	12/18/99
B 3.8.2-5	12	DRR 02-1062	9/26/02
B 3.8.2-6	12	DRR 02-1062	9/26/02
B 3.8.2-7	12	DRR 02-1062	9/26/02
B 3.8.3-1	1	DRR 99-1624	12/18/99
B 3.8.3-2	0	Amend. No. 123	12/18/99
B 3.8.3-3	0	Amend. No. 123	12/18/99
B 3.8.3-4	1	DRR 99-1624	12/18/99
B 3.8.3-5	0	Amend. No. 123	12/18/99
B 3.8.3-6	0	Amend. No. 123	12/18/99
B 3.8.3-7	12	DRR 02-1062	9/26/02
B 3.8.3-8	1	DRR 99-1624	12/18/99
B 3.8.3-9	0	Amend. No. 123	12/18/99
B 3.8.4-1	0	Amend. No. 123	12/18/99
B 3.8.4-2	0	Amend. No. 123	12/18/99
B 3.8.4-3	0	Amend. No. 123	12/18/99
B 3.8.4-4	0	Amend. No. 123	12/18/99
B 3.8.4-5	0	Amend. No. 123	12/18/99
B 3.8.4-6	0	Amend. No. 123	12/18/99
B 3.8.4-7	6	DRR 00-1541	3/13/01
B 3.8.4-8	0	Amend. No. 123	12/18/99
B 3.8.4-9	2	DRR 00-0147	4/24/00
B 3.8.5-1	0	Amend. No. 123	12/18/99
B 3.8.5-2	0	Amend. No. 123	12/18/99
B 3.8.5-3	0	Amend. No. 123	12/18/99
B 3.8.5-4	12	DRR 02-1062	9/26/02
B 3.8.5-5	12	DRR 02-1062	9/26/02
B 3.8.6-1	0	Amend. No. 123	12/18/99
B 3.8.6-2	0	Amend. No. 123	12/18/99
B 3.8.6-3	0	Amend. No. 123	12/18/99
B 3.8.6-4	0	Amend. No. 123	12/18/99
B 3.8.6-5	0	Amend. No. 123	12/18/99
B 3.8.6-6	0	Amend. No. 123	12/18/99
B 3.8.7-1	0	Amend. No. 123	12/18/99
B 3.8.7-2	5	DRR 00-1427	10/12/00
B 3.8.7-3	0	Amend. No. 123	12/18/99
B 3.8.7-4	0	Amend. No. 123	12/18/99
B 3.8.8-1	0	Amend. No. 123	12/18/99
B 3.8.8-2	0	Amend. No. 123	12/18/99

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TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.8-3	0	Amend. No. 123	12/18/99
B 3.8.8-4	12	DRR 02-1062	9/26/02
B 3.8.8-5	12	DRR 02-1062	9/26/02
B 3.8.9-1	0	Amend. No. 123	12/18/99
B 3.8.9-2	0	Amend. No. 123	12/18/99
B 3.8.9-3	0	Amend. No. 123	12/18/99
B 3.8.9-4	0	Amend. No. 123	12/18/99
B 3.8.9-5	0	Amend. No. 123	12/18/99
B 3.8.9-6	0	Amend. No. 123	12/18/99
B 3.8.9-7	0	Amend. No. 123	12/18/99
B 3.8.9-8	1	DRR 99-1624	12/18/99
B 3.8.9-9	0	Amend. No. 123	12/18/99
B 3.8.10-1	0	Amend. No. 123	12/18/99
B 3.8.10-2	0	Amend. No. 123	12/18/99
B 3.8.10-3	0	Amend. No. 123	12/18/99
B 3.8.10-4	0	Amend. No. 123	12/18/99
B 3.8.10-5	12	DRR 02-1062	9/26/02
B 3.8.10-6	12	DRR 02-1062	9/26/02
TAB – B 3.9 REFUELING OPERATIONS			
B 3.9.1-1	0	Amend. No. 123	12/18/99
B 3.9.1-2	19	DRR 04-1414	10/12/04
B 3.9.1-3	19	DRR 04-1414	10/12/04
B 3.9.1-4	19	DRR 04-1414	10/12/04
B 3.9.2-1	0	Amend. No. 123	12/18/99
B 3.9.2-2	0	Amend. No. 123	12/18/99
B 3.9.2-3	0	Amend. No. 123	12/18/99
B 3.9.3-1	12	DRR 02-1062	9/26/02
B 3.9.3-2	12	DRR 02-1062	9/26/02
B 3.9.3-3	21	DRR 05-0707	4/20/05
B 3.9.4-1	23	DRR 05-1995	9/28/05
B 3.9.4-2	13	DRR 02-1458	12/03/02
B 3.9.4-3	23	DRR 05-1995	9/28/05
B 3.9.4-4	23	DRR 05-1995	9/28/05
B 3.9.4-5	13	DRR 02-1458	12/03/02
B 3.9.4-6	23	DRR 05-1995	9/28/05
B 3.9.5-1	0	Amend. No. 123	12/18/99
B 3.9.5-2	12	DRR 02-1062	9/26/02
B 3.9.5-3	12	DRR 02-1062	9/26/02
B 3.9.5-4	12	DRR 02-1062	9/26/02
B 3.9.6-1	0	Amend. No. 123	12/18/99
B 3.9.6-2	19	DRR 04-1414	10/12/04
B 3.9.6-3	12	DRR 02-1062	9/26/02
B 3.9.6-4	12	DRR 02-1062	9/26/02
B 3.9.7-1	0	Amend. No. 123	12/18/99
B 3.9.7-2	0	Amend. No. 123	12/18/99
B 3.9.7-3	0	Amend. No. 123	12/18/99

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Note 1 The page number is listed on the center of the bottom of each page.

Note 2 The revision number is listed in the lower right hand corner of each page. The Revision number will be page specific.

Note 3 The change document will be the document requesting the change. Amendment No. 123 issued the improved Technical Specifications and associated Bases which affected each page. The NRC has indicated that Bases changes will not be issued with License Amendments. Therefore, the change document should be a DRR number in accordance with AP 26A-002.

Note 4 The date effective or implemented is the date the Bases pages are issued by Document Control.