Exelon Nuclear

Clinton Power Station
8401 Power Road
Clinton, IL 61727

U-603987
October 1, 2010

10 CFR 50.36

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

Clinton Power Station, Unit 1
Facility Operating License
NRC Docket No. 50-461

Subject: Transmittal of Revision 13 to the Clinton Power Station Technical Specification Bases

In accordance with Clinton Power Station (CPS) Technical Specification 5.5.11, "Technical Specification (TS) Bases Control Program," Exelon Generation Company (EGC), LLC is transmitting the revised pages constituting Revision 13 to the CPS TS Bases. The changes associated with this revision were processed in accordance with CPS TS 5.5.11. Compliance with CPS TS 5.5.11 requires updates to the TS Bases to be submitted to the NRC at a frequency consistent with 10 CFR 50.71, "Maintenance of records, making of reports," paragraph (e).

There are no regulatory commitments in this letter.

Should you have any questions concerning this information, please contact Mr. Jim Peterson at (217) 937-2810.

Respectfully,

Daniel J. Kemper
Regulatory Assurance Manager
Clinton Power Station

JLP/blf

Attachment 1 – Revision 13 to the CPS Technical Specification Bases List of Pages
Attachment 2 – Copies of Bases Revision 13 Pages

cc: Regional Administrator, NRC Region III
NRC Senior Resident Inspector, Clinton Power Station

A001
NRR

Attachment 1 to U-603987

Revision 13 to the CPS Technical Specification Bases List of Pages

B3.1-7	B3.1-16	B3.1-19	B3.1-20
B3.3-35	B3.3-233	B3.3-234	B3.3-235
B3.3-236			
B3.4-22	B3.4-32	B3.4-32a	
B3.5-7	B3.5-8	B3.5-9	B3.5-10
B3.5-11	B3.5-12	B3.5-13	B3.5-14
B3.5-14a	B3.5-14b		
B3.6-36	B3.6-37	B3.6-37a	B3.6-37b
B3.6-38	B3.6-41	B3.6-42	B3.6-43
B3.6-47c	B3.6-47d	B3.6-58	B3.6-58a
B3.6-58b	B3.6-59	B3.6-86	B3.6-87
B3.6-88	B3.6-88a	B3.6-88b	B3.6-98
B3.6-99	B3.6-100	B3.6-101	B3.6-101a
B3.6-130	B3.6-131	B3.6-132	
B3.7-4	B3.7-5	B3.7-6	B3.7-6a
B3.7-6b	B3.7-13	B3.7-14	B3.7-15
B3.7-16	B3.7-16a	B3.7-16b	B3.7-16c
B3.7-16d	B3.7-19	B3.7-19a	B3.7-21
B3.7-21a	B3.7-23	B3.7-24	B3.7-24a
B3.7-24b			
B3.8-12	B3.8-13	B3.8-13a	B3.8-13b
B3.8-14	B3.8-15	B3.8-16	B3.8-17
B3.8-18	B3.8-19	B3.8-19a	B3.8-19b
B3.8-20	B3.8-21	B3.8-22	B3.8-24
B3.8-25	B3.8-26	B3.8-27	B3.8-28
B3.8-29	B3.8-31	B3.8-32	B3.8-32a
B3.8-45	B3.8-55	B3.8-56	B3.8-57
B3.8-58	B3.8-71	B3.8-71b	B3.8-72
B3.8-73	B3.8-85	B3.8-86	B3.8-87
B3.9-2			

Attachment 2 to U-603987
Copies of Bases Revision 13 Pages

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.1.1.1 (continued) With regard to SDM values obtained pursuant to this SR, as determined from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 6).
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. USAR, Section 15.4.9. 3. NEDO-21231, "Banked Position Withdrawal Sequence," Section 4.1, January 1977. 4. USAR, Section 15.4.1.1. 5. NEDE-24011-P-A, "GE Standard Application for Reactor Fuel, GESTAR II" (latest approved revision). 6. Calculation IP-0-0002.

BASES

ACTIONS

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

manner. Isolating the control rod from scram prevents damage to the CRDM. The control rod can be isolated from scram by isolating the hydraulic control unit from scram and normal drive and withdraw pressure, yet still maintain cooling water to the CRD.

Monitoring of the insertion capability for each withdrawn control rod must also be performed within 24 hours. SR 3.1.3.3 performs periodic tests of the control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. The allowed Completion Time of 24 hours provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests. Required Action A.2 has a modified time zero Completion Time. The 24 hour Completion Time for this Required Action starts when the withdrawn control rod is discovered to be stuck and THERMAL POWER is greater than the actual low power setpoint (LPSP) of the rod pattern control system (RPCS), since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RPCS (LCO 3.3.2.1, "Control Rod Block Instrumentation").

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion an additional control rod would have to be assumed to have failed to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 4 is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined, to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods. The 24 hour Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indications in the control room.

SR 3.1.3.2

Deleted

SR 3.1.3.3

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. This Surveillance is modified by a note identifying that the Surveillance is not required to be performed when THERMAL POWER is less than or equal to the actual LPSP of the RPCS since the notch insertions may not be compatible with the requirements of BPWS (LCO 3.1.6) and the RPCS (LCO 3.3.2.1). This note also provides a time allowance (i.e., the associated SR Frequency plus the extension allowed by SR 3.0.2) such that the Surveillance is not required to be performed until the next scheduled control rod testing. This note provides this allowance to prevent unnecessary perturbations in reactor operation to perform this testing on a control rod. The 31 day Frequency takes into account operating experience related to changes in CRD performance. At any time, if a control rod is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.3 (continued)

immovable, a determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken.

SR 3.1.3.4

Verifying the scram time for each control rod to notch position 13 is ≤ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown functions. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

With regard to scram time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 9).

SR 3.1.3.5

Coupling verification is performed to ensure the control rod is connected to the CRDM and will perform its intended function when necessary. The Surveillance requires verifying that a control rod does not go to the withdrawn overtravel position when it is fully withdrawn. The overtravel position feature provides a positive check on the coupling integrity, since only an uncoupled CRD can reach the overtravel position. If the control rod goes to the withdrawn overtravel position, the control rod drive mechanism can be inserted to attempt recoupling, within the limitations of Condition C. This verification is required

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the capability to detect local reactivity changes in the core during refueling is degraded. CORE ALTERATIONS must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity, given that fuel is present in the core. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe, conservative position.

Action (once required to be initiated) to insert control rods must continue until all insertable rods in core cells containing one or more fuel assemblies are inserted.

SURVEILLANCE REQUIREMENTS

The SRs for each SRM Applicable MODE or other specified condition are found in the SRs column of Table 3.3.1.2-1.

SR 3.3.1.2.1 and SR 3.3.1.2.3

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

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

(continued)

BASES

APPLICABILITY (continued)

in MODES 1, 2, and 3, and MODES 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

A.1

If the power monitoring assembly for an inservice power supply (UPS or alternate) is inoperable, or the power monitoring assembly in each inservice power supply is inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore the assembly to OPERABLE status for each inservice power supply. If the inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supplies must be removed from service within 1 hour (Required Action A.1). An alternate power supply with OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition B or C, as applicable, must be entered and its Required Actions taken.

In addition to the actions identified in Condition A, if the frequency of the supply to the RPS solenoid bus is $\leq$ 57 Hz, the OPERABILITY of all Class 1E equipment which could have been subjected to the abnormal frequency on the associated RPS solenoid bus must be demonstrated by the performance of a CHANNEL FUNCTIONAL TEST or CHANNEL CALIBRATION, as required. These tests should be performed within 24 hours of discovering the underfrequency condition.

B.1

If any Required Action and associated Completion Time of Condition A is not met in MODE 1, 2, or 3, the plant must be brought to a MODE in which overall plant risk is minimized.

(continued)

BASES

ACTIONS

B.1 (continued)

The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

If any Required Action and associated Completion Time of Condition A is not met in MODE 4 or 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies (Required Action C.1). This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1 (continued)

This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 3).

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.3

Performance of a system functional test demonstrates a required system actuation (simulated or actual) signal. The logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.3 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance.

REFERENCES

1. USAR, Section 8.3.1.1.3.1.

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

3 NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

BASES

ACTIONS (continued)

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hour Completion Time is based on a reliability study, as provided in Reference 12.

D.1

If any Required Action and associated Completion Time of Condition A, B, or C are not met, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 13) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action D.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

E.1

The LCO requires seven ADS valves to be OPERABLE to provide the ADS function. Reference 14 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only six ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design basis LOCA could result in the minimum required ECCS equipment not being available. Since both a portion of a high pressure (ADS) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

G.1

If any Required Action and associated Completion Time of Condition E or F are not met or if two or more ADS valves are inoperable, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 13) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS

G.1 (continued)

Required Action G.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a degraded condition not specifically justified for continued operation, and may be in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCS System, LPCS System, and LPCI subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The 31 day Frequency is based on operating experience, on the procedural controls governing system operation, and on the gradual nature of void buildup in the ECCS piping.

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves potentially capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve alignment would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

This SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. This allows operation in the RHR shutdown cooling mode during MODE 3 if necessary.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.3

Verification every 31 days that ADS accumulator supply pressure is ≥ 140 psig assures adequate air pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The designed pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure (Ref. 15). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of 140 psig is provided by the Instrument Air System. The 31 day Frequency takes into consideration administrative control over operation of the Instrument Air System and alarms for low air pressure.

With regard to ADS accumulator supply pressure values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Ref. 17).

SR 3.5.1.4

The performance requirements of the ECCS pumps are determined through application of the 10 CFR 50, Appendix K, criteria (Ref. 8). This periodic Surveillance is performed (in accordance with the ASME Code requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The pump flow rates are verified with a pump differential pressure that is sufficient to overcome the RPV pressure expected during a LOCA. The pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing. The Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

With regard to pump flow rates and differential pressures values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Refs. 18, 19, 20). Calculations 01HP15, 01LP16 and 01RH26 determine the margin between actual pump performance capability and the system design requirements and the Analyzed Design Limits as established by SAFER/GESTR. These margins are large enough to account for the instrument indication uncertainties and the lower EDG frequency limit per SR 3.8.1.2 and therefore the specified limit in this SR can be considered to be a nominal value (Refs. 18, 19, 20, 24).

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves to their required positions. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the RCIC storage tank to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.6

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.7 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.5.1.7

A manual actuation of each required ADS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by Method 1, plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 22), prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

Conditions for testing and provides a reasonable time to complete the SR. If performed by Method 2, valve OPERABILITY has been demonstrated for all installed ADS valves based upon the successful operations of a test sample of S/RVs.

1. Manual actuation of the ADS valve, with verification of the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitoring). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is consistent with the pressure recommended by the valve manufacturer.

2. The sample population of S/RVs tested to satisfy SR 3.4.4.1 will also be stroked in the relief mode during "as-found" testing to verify proper operation of the S/RV. The successful performance of the test sample of S/RVs provides reasonable assurance that all ADS valves will perform in a similar fashion. After the S/RVs are replaced, the relief-mode actuator of the newly-installed S/RVs will be uncoupled from the S/RV stem, and cycled to ensure that no damage has occurred to the S/RV during transportation and installation. Following cycling, the relief-mode actuator is recoupled and the proper positioning of the stem nut is independently verified. This verifies that each replaced S/RV will properly perform its intended function.

SR 3.5.1.6 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function. The STAGGERED TEST BASIS Frequency ensures that both solenoids for each ADS valve relief-mode actuator are alternately tested. The Frequency of the required relief-mode actuator testing is based on the tests required by ASME OM, Part 1, (Ref. 22) as implemented by the Inservice Testing Program of Specification 5.5.6. The testing Frequency required by the Inservice Testing Program is based on operating experience and valve performance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.8

This SR ensures that the ECCS RESPONSE TIMES are within limits for each of the ECCS injection and spray subsystems. The response time limits (i.e., ≤42 seconds for the LPCI subsystems, ≤41 seconds for the LPCS subsystem, and ≤27 seconds for the HPCS system) are specified in applicable surveillance test procedures. This SR is modified by a Note which identifies that the associated ECCS actuation instrumentation is not required to be response time tested. This is supported by Reference 16.

Response time testing of the remaining subsystem components is required. However, of the remaining subsystem components, the time for each ECCS pump to reach rated speed is not directly measured in the response time tests. The time(s) for the ECCS pumps to reach rated speed is bounded, in all cases, by the time(s) for the ECCS injection valve(s) to reach the full-open position. Plant-specific calculations show that all ECCS motor start times at rated voltage are less than two seconds. In addition, these calculations show that under degraded voltage conditions, the time to rated speed is less than five seconds.

ECCS RESPONSE TIME tests are conducted every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

With regard to ECCS RESPONSE TIME values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 21).

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 6.3.2.2.3.
2. USAR, Section 6.3.2.2.4.
3. USAR, Section 6.3.2.2.1.
4. USAR, Section 6.3.2.2.2.
5. USAR, Section 15.2.8.
6. USAR, Section 15.6.4.
7. USAR, Section 15.6.5.
8. 10 CFR 50, Appendix K.
9. USAR, Section 6.3.3.
10. 10 CFR 50.46.
11. USAR, Section 6.3.3.3.
12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
13 NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
14. USAR, Table 6.3-8.
15. USAR, Section 7.3.1.1.1.4.
16. NEDO-32291-A, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994.
17. Calculation IP-0-0044.
18. Calculations 01HP09/10/11/15, IP-C-0042.
19. Calculations 01LP08/11/14/16, IP-C-0043.
20. Calculations 01RH19/20/23/24/26, IP-C-0041.
21. Calculation IP-0-0024.
22. ASME/ANSI OM-1987, Operation and Maintenance of Nuclear Power Plants, Part 1.
23. ASME Code for Operation and Maintenance of Nuclear Power Plants.
24. NEDC-32945P, "Clinton Power Station SAFER/GESTR-LOCA Analysis," June 2000.

APPLICABLE SAFETY ANALYSES (continued)

LLS S/RVs are specified, all five LLS S/RVs do not operate in any DBA analysis.LLS valves satisfy Criterion 3 of the NRC Policy Statement

LCO

Five LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analysis (Ref. 1). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the S/RVs.

APPLICABILITY

In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of S/RVs. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the LLS valves OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one LLS valve inoperable, the remaining OPERABLE LLS valves are adequate to perform the designed function. However, the overall reliability is reduced. The 14 day Completion Time takes into account the redundant capability afforded by the remaining LLS S/RVs and the low probability of an event in which the remaining LLS S/RV capability would be inadequate.

B.1

If the inoperable LLS valve cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a.

(continued)

ACTIONS

B.1 (continued)

However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If two or more LLS valves are inoperable, there could be excessive short duration S/RV cycling during an overpressure event. The plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

A manual actuation of each required LLS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by Method 1, plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 3), prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If performed by Method 2, valve OPERABILITY has been demonstrated for all installed LLS valves based upon the successful operation of a test sample of S/RVs.

1. Manual actuation of the LLS valve, with verification of the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitoring). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the LLS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is consistent with the pressure recommended by the valve manufacturer.

2. The sample population of S/RVs tested to satisfy SR 3.4.4.1 will also be stroked in the relief mode during "as-found" testing to verify proper operation of the S/RV. The successful performance of the test sample of S/RVs provides reasonable assurance that all LLS valves will perform in similar fashion. After the S/RVs are replaced, the relief-mode actuator of the newly-installed S/RVs will be uncoupled from the S/RV stem, and cycled to ensure that no damage has occurred to the S/RV during transportation and installation. Following cycling, the relief-mode actuator is recoupled and the proper positioning of the stem nut is independently verified. This verifies that each replaced S/RV will properly perform its intended function.

The Frequency of the required relief-mode actuator testing is based on the tests required by ASME OM Part 1 (Ref. 3), as implemented by the Inservice Testing Program of Specification 5.5.6. The testing Frequency required by the Inservice Testing Program is based on operating experience and valve performance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.6.2

The LLS designed S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the automatic LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents a reactor pressure vessel pressure blowdown.

(continued)

REFERENCES

1. USAR, Section 5.2.2.2.3.

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

3. ASME/ANSI OM-1987, Operation and Maintenance of Nuclear Power Plants, Part 1.

This Page Left Intentionally Blank

ACTIONS (continued)

B.1

With two RHR containment spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the drywell bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to remove heat from primary containment are available.

C.1

If the inoperable RHR containment spray subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action C.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

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

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR containment spray mode flow path provides assurance that the proper flow paths will exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR is justified because the valves are operated under procedural control and because improper valve position would affect only a single subsystem. This Frequency has been shown to be acceptable based on operating experience.

A Note has been added to this SR that allows RHR containment spray subsystems to be considered OPERABLE during alignment to and operation in the RHR shutdown cooling mode when below the RHR cut in permissive pressure in MODE 3, if capable of being manually realigned and not otherwise inoperable. At these low pressures and decay heat levels (the reactor is shut down in MODE 3), a reduced complement of subsystems should provide the required containment pressure mitigation function thereby allowing operation of an RHR shutdown cooling loop when necessary.

SR 3.6.1.7.2

Verifying each RHR pump develops a flow rate ≥ 3800 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded below the required flow rate during the cycle. It is tested in the pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in primary containment. Although this SR is satisfied by running the pump in the suppression pool cooling mode, the test procedures that satisfy this SR include appropriate acceptance criteria to account for the higher pressure requirements resulting from aligning the RHR System in the containment spray mode. The Frequency of this SR is in accordance with the Inservice Testing Program.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.7.3

This SR verifies that each RHR containment spray subsystem automatic valve actuates to its correct position upon receipt of an actual or simulated automatic actuation signal. Actual spray initiation is not required to meet this SR. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.3.5 overlaps this SR to provide complete testing of the safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.7.4

This Surveillance is performed following activities that could result in nozzle blockage to verify that the spray nozzles are not obstructed and that flow will be provided when required. Such activities may include a loss of foreign material control (of if it cannot be assured), following a major configuration change, or following an inadvertent actuation of containment spray. This Surveillance is normally performed by an air or smoke flow test. The Frequency is adequate due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 6.2.1.1.5.
2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
3. ASME Code for Operation and Maintenance of Nuclear Power Plants.
4. USAR, Section 5.4.7

ACTIONS (continued)

C.1.

If the inoperable FWLCS subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action C.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1

A system functional test of each FWLCS subsystem is performed to ensure that each FWLCS subsystem will operate through its operating sequence. This includes verifying automatic positioning of valves and operation of each interlock, and that the necessary check valves open. Adequacy of the associated RHR pumps to deliver FWLCS flow rates required to meet the assumptions made in the supporting analyses concurrent with other modes was demonstrated during acceptance testing of the system after installation. Periodic verification of the capabilities of the RHR pumps is performed under SR 3.5.1.4.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 15.6.5.

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

ACTIONS (continued)

B.1

If the Required Action and required Completion Time of Condition A cannot be met, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

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

C.1 and C.2

If two RHR suppression pool cooling subsystems are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable, based on operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.3.2

Verifying each RHR pump develops a flow rate ≥ 4550 gpm, with flow through the associated heat exchanger to the suppression pool, ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME (Ref. 3). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

With regard to RHR pump flow rate values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties for implementation in the associated plant procedures. (Ref. 5).

REFERENCES

1. USAR, Section 6.2.
2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
3. ASME Code for Operation and Maintenance of Nuclear Power Plants.
4. USAR, Section 5.4.7.
5. Calculations 01RH20/25 and IP-C-0041.

This page intentionally left blank

ACTIONS

A.1 (continued)

containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1

If the secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 3), because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Movement of recently irradiated fuel assemblies in the primary or secondary containment and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. Movement of recently irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

(continued)

ACTIONS

C.1 and C-2 (continued)

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend

(continued)

ACTIONS

C.1 and C.2 (continued)

movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

With regard to secondary containment vacuum values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 4).

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed, except when the access opening is being used for entry and exit. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other controls on secondary containment access openings.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to draw down pressure in the secondary containment to ≥ 0.25 inches vacuum water gauge within the time required and maintain pressure in the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 4400 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 and SR 3.6.4.1.5 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.4, which demonstrates that secondary containment can be drawn down to ≥ 0.25 inches of vacuum water gauge in the required time using one SGT subsystem.

Specifically, the required drawdown time limit is based on ensuring that the SGT system will draw down the secondary containment pressure to ≥ 0.25 inches of vacuum water gauge within 12 minutes (i.e., 10 minutes from start of gap release which occurs 2 minutes after LOCA initiation) under LOCA conditions. Typically, however, the conditions under which drawdown testing is performed pursuant to SR 3.6.4.1.4 are different than those assumed for LOCA conditions. For this reason, and because test results are dependent on or influenced by certain plant and/or atmospheric conditions that may be in effect at the time testing is performed, it is necessary to adjust the test acceptance criteria (i.e., the required drawdown time) to account for such test conditions. Conditions or factors that may impact the test results include wind speed, whether the turbine building ventilation system is running, and whether the containment equipment hatch is open (when the test is performed during plant shutdown/outage conditions). The acceptance criteria for the drawdown test are thus based on a computer model (Ref. 7), verified by actual performance of drawdown tests, in which the drawdown time determined for accident conditions is adjusted to account for performance of the test during normal but certain plant conditions. The test acceptance criteria are specified in the applicable plant test procedure(s). Since the drawdown time is dependent upon secondary containment integrity, the drawdown requirement cannot be met if the secondary containment boundary is not intact.

SR 3.6.4.1.5 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate of ≤ 4400 cfm. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

conditions. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements which serves the primary purpose for ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY. Operating experience has shown these components usually pass the Surveillance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

With regard to drawdown time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Refs. 5, 6).

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 15.7.4.
3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
4. Calculation IP-0-0082.
5. Calculation IP-0-0083.
6. Calculation IP-0-0084.
7. Calculation 3C10-1079-001.

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs) or during movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours) in the primary or secondary containment.

ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE SGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT subsystem and the low probability of a DBA occurring during this period.

B.1

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 9) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

ACTIONS

B.1 (continued)

Required Action B.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2.1 and C.2.2

During movement of recently irradiated fuel assemblies in the primary or secondary containment or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. This action should be chosen if the OPDRVs could be impacted by a loss of offsite power. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

(continued)

ACTIONS (continued)

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT System may not be capable of supporting the required radioactivity release control function. Therefore, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 9) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Required Action D.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

E.1 and E.2

When two SGT subsystems are inoperable, if applicable, movement of recently irradiated fuel assemblies in the primary and secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem from the main control room for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

With regard to operating time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 10).

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber bypass leakage and efficiency, minimum system flow rate, combined HEPA filter and charcoal adsorber pressure drop, and heater dissipation. The frequencies for performing the SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4) and include testing initially, after 720 hours of system operation, once per 24 months, and following painting, fire, or chemical release in any ventilation zone communicating with the system. The laboratory test results will be verified to be within limits within 31 days of removal of the sample from the system. Additional information is discussed in detail in the VFTP.

With regard to filter testing values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 11).

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem automatically starts upon receipt of an actual or simulated initiation signal.

The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR requires verification that the SGT filter cooling bypass damper can be opened and the fan started. This ensures that the ventilation mode of SGT System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.2.3.
3. USAR, Section 15.6.5.
4. Regulatory Guide 1.52.
5. USAR, Section 6.5.1.
6. USAR, Section 15.6.4.
7. USAR Appendix A.
8. ASME/ANSI N510-1980.
9. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002
10. Calculation IP-0-0086.
11. Calculation IP-0-0087.

ACTIONS

A.1 (continued)

A Note has been added to provide clarification that separate Condition entry is allowed for each vacuum relief subsystem not closed.

B.1

With one drywell post-LOCA vacuum relief subsystem inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 30 days. In these Conditions, the remaining OPERABLE vacuum relief subsystems are adequate to perform the depressurization mitigation function since three 10-inch lines remain available. The 30 day Completion Time takes into account the redundant capability afforded by the remaining subsystems, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

C.1

With two or more drywell post-LOCA vacuum relief subsystems inoperable for reasons other than Condition A, the inoperable subsystems must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time takes into account a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

D.1 and D.2

If the inoperable drywell post-LOCA vacuum relief subsystem(s) cannot be closed within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach

(continued)

ACTIONS

D.1 and D.2 (continued)

the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

If one drywell post-LOCA vacuum relief subsystem is inoperable for reasons other than Condition A or two or more drywell post-LOCA vacuum relief subsystems are inoperable for reasons other than Condition A, and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Required Action E.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.6.1

Each drywell post-LOCA vacuum relief valve is verified to be closed (except when being tested in accordance with SR 3.6.5.6.2 and SR 3.6.5.6.3 or when the drywell post-LOCA vacuum relief valves are performing their intended design function) to ensure that this potential large drywell bypass leakage path is not present. This Surveillance is normally performed by observing the drywell post-LOCA vacuum relief valve position indication. The 7 day Frequency is based on engineering judgment, is considered adequate in view of other indications of drywell post-LOCA vacuum relief valve status available to the plant personnel, and has been shown to be acceptable through operating experience.

(continued)

SURVEILLANCE REQUIREMEN

SR 3.6.5.6.1 (continued)

Two Notes are added to this SR. The first Note allows drywell post-LOCA vacuum relief valves opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening drywell post-LOCA vacuum relief valves are controlled by plant procedures and do not represent inoperable drywell post-LOCA vacuum relief valves. A second Note is included to clarify that valves open due to an actual differential pressure, are not considered as failing this SR.

SR 3.6.5.6.2

Each drywell post-LOCA vacuum relief valve must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This provides assurance that the safety analysis assumptions are valid. A 31 day Frequency was chosen to provide additional assurance that the drywell post-LOCA vacuum relief valves are OPERABLE.

SR 3.6.5.6.3

Verification of the drywell post-LOCA vacuum relief valve opening differential pressure is necessary to ensure that the safety analysis assumptions of $\leq$ 0.2 psid for drywell vacuum relief are valid. The safety analysis assumes that the drywell post-LOCA vacuum relief valves will start opening when the dry well pressure is approximately 0.2 psid less than the containment and will be fully open when this differential pressure is 0.5 psid. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for violating the drywell boundary. Operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 6.2.

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

ACTIONS

A.1

If the UHS is inoperable (i.e., the UHS water volume is not within the limit), action must be taken to restore the inoperable UHS to OPERABLE status within 90 days. The 90 day Completion Time is reasonable considering the time required to restore the required UHS volume, the margin contained in the available heat removal capacity, and the low probability of a DBA occurring during this period.

B.1

If the Division 1 or 2 SX subsystem is inoperable, it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE Division 1 or 2 SX subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE Division 1 or 2 SX subsystem could result in loss of the SX function. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

The Required Action is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources—Operating," and LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable SX subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

C.1

If the Required Action and associated Completion Time of Condition B is not met, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed

(continued)

BASES

ACTIONS

C.1 (continued)

Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Required Action C.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

D.1 and D.2

If the Required Action and associated Completion Time of Condition A or B are not met, or both Division 1 and 2 SX subsystems are inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies UHS water volume is ≥ 593 acre-feet (excluding sediment). The Surveillance Frequency is in accordance with UHS Erosion, Sediment Monitoring and Dredging Program.

With regard to UHS water volume values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 9).

SR 3.7.1.2

Verifying the correct alignment for each manual, power operated, and automatic valve in each Division 1 and 2 SX subsystem flow path provides assurance that the proper flow paths will exist for Division 1 and 2 SX subsystem operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

Isolation of the SX subsystem to components or systems does not necessarily affect the OPERABILITY of the associated SX subsystem. As such, when all SX pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the associated SX subsystem needs to be evaluated to determine if it is still OPERABLE. Alternatively, it is acceptable and conservative to declare an SX subsystem inoperable when a branch connection is isolated or a supported ventilation system is inoperable.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.3

This SR verifies that the automatic isolation valves of the Division 1 and 2 SX subsystems will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal and is performed with the plant shut down. This SR also verifies the automatic start capability of the SX pump in each subsystem.
Operating experience has shown that these components usually pass the SR. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. USAR, Section 9.2.1.2.
3. USAR, Table 9.2-3.
4. USAR, Section 6.2.1.1.3.3.
5. USAR, Chapter 15.
6. USAR, Section 6.2.2.3.
7. USAR, Table 6.2-2.
8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
9. Calculation IP-0-0095.

This page intentionally left blank

B 3.7.2 Division 3 Shutdown Service Water Subsystem (SX)

BASES

BACKGROUND

The Division 3 SX subsystem is designed to provide cooling water for the removal of heat from components of the Division 3 High Pressure Core Spray (HPCS) System.

The Division 3 SX subsystem consists of one cooling water header (Division 3 subsystem of the SX System), and the associated subsystem pump, piping, and valves. The Ultimate Heat Sink (UHS) is considered part of the SX System (LCO 3.7.1, "Division 1 and 2 Shutdown Service Water (SX) Subsystems and Ultimate Heat Sink (UHS)").

Cooling water is pumped from a UHS water source by the Division 3 SX pump to the essential components through the Division 3 SX supply header. After removing heat from the components, the water is discharged to the UHS.

The Division 3 SX subsystem specifically supplies cooling water to the Division 3 HPCS diesel generator jacket water coolers and HPCS pump room cooler. The Division 3 SX pump is sized such that it will provide adequate cooling water to the Division 3 equipment required for safe shutdown. Following a Design Basis Accident or transient, the Division 3 SX subsystem will operate automatically and without operator action as described in the USAR, Section 9.2.1.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The ability of the Division 3 SX to provide adequate cooling to the HPCS System is an implicit assumption for safety analyses evaluated in the USAR, Chapters 6 and 15 (Refs. 2 and 3, respectively).

The Division 3 SX subsystem satisfies Criterion 3 of the NRC Policy Statement.

LCO

The Division 3 SX subsystem is required to be OPERABLE to ensure that the HPCS System will operate as required. An OPERABLE Division 3 SX subsystem consists of an OPERABLE

(continued)

APPLICABILITY

In MODES 1, 2, and 3, the Control Room Ventilation System must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA, since the DBA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Control Room Ventilation System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During operations with a potential for draining the reactor vessel (OPDRVs);

b. During CORE ALTERATIONS; and

c. During movement of irradiated fuel assemblies in the primary or secondary containment.

ACTIONS

A.1

With one Control Room Ventilation subsystem inoperable for reasons other than an inoperable CRE boundary, the inoperable Control Room Ventilation subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE Control Room Ventilation subsystem is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE subsystem could result in loss of Control Room Ventilation System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

B.1

In MODE 1, 2, or 3, if the inoperable Control Room Ventilation subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes overall plant risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 7) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed

(continued)

ACTIONS

B.1 (continued)

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

Required Action B.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

C.1, C.2, and C3

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals and smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e, actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA during this time period, and the use of mitigating actions. The 90 day Completion Time is

(continued)

ACTIONS

C.1, C.2, and C3 (continued)

reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability the CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

D.1 and D.2

In MODE 1, 2, or 3, if the CRE boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

E.1, E.2.1, E.2.2, and E.2.3

The Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the inoperable Control Room Ventilation subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE Control Room Ventilation subsystem may be placed in the high radiation mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action E.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require the Control Room Ventilation subsystem to be in the high radiation mode of operation. This places the unit in a condition that minimizes the accident risk.

(continued)

BASES

ACTIONS

E.1, E.2.1, E.2.2, and E.2.3 (continued)

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the primary and secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

F.1

If both Control Room Ventilation subsystems are inoperable in MODE 1, 2, or 3 for reasons other than an inoperable CRE boundary (i.e., Condition C), the Control Room Ventilation System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 7) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions is an orderly manner and without challenging plant systems.

Required Action F.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

(continued)

ACTIONS (continued)

G.1, G.2, and G.3

During movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two Control Room Ventilation subsystems inoperable or with one or more Control Room Ventilation subsystems inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require treatment of the control room air. This places the unit in a condition that minimizes the accident risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the primary and secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 and SR 3.7.3.2

This SR verifies that a subsystem in a standby mode starts on demand and continues to operate. Standby systems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing each subsystem once every month provides an adequate check on this system. Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. The Makeup Filter System must be operated from the main control room for ≥ 10 continuous hours with the heaters energized. The Recirculation Filter System (without heaters) need only be operated for ≥ 15 minutes to demonstrate the function of the system. Furthermore, the 31 day Frequency is based on the known reliability of the equipment and the two subsystem redundancy available.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 and SR 3.7.3.2 (continued)

With regard to subsystem operation time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 8, 9).

SR 3.7.3.3

This SR verifies that the required Control Room Ventilation System testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber bypass leakage and efficiency, minimum system flow rate (scfm), combined HEPA filter and charcoal adsorber pressure drop, and heater dissipation in accordance with Regulatory Guide 1.52 (Ref. 10). The Frequencies for performing the Control Room Ventilation System filter tests are also in accordance with Regulatory Guide 1.52 (Ref.10). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.3.4

This SR verifies that each Control Room Ventilation subsystem starts and operates on an actual or simulated high radiation initiation signal. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.5

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition C must be entered. Required Action C.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 11) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 12). These compensatory measures may also be used as mitigating actions as required by Required Action C.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 13). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 6.5.1.

2. USAR, Section 9.4.1.

3. USAR, Chapter 6.

4. USAR, Chapter 15.

5. USAR, Section 6.4.

6. USAR, Section 9.5.

7. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002

8. Calculation IP-O-0096.

9. Calculation IP-O-0097.

10. Regulatory Guide 1.52, Revision 2, March 1978.

11. Regulatory Guide 1.196.

12. NEI 99-03, "Control Room Habitability Assessment," June 2001.

13. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 10, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

BASES (continued)

ACTIONS

A.1

With one control room AC subsystem inoperable, the inoperable control room AC subsystem must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE control room AC subsystem is adequate to perform the control room air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of the control room air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring Control Room Ventilation System operation in the high radiation mode, the consideration that the remaining subsystem can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

If both control room AC subsystems are inoperable, the Control Room AC System may not be capable of performing its intended function. Therefore, the control room area temperature is required to be monitored to ensure that temperature is being maintained low enough that equipment in the control room is not adversely affected. With the control room temperature being maintained within the temperature limit, 7 days is allowed to restore a control room AC subsystem to OPERABLE status. This Completion Time is reasonable considering that the control room temperature is being maintained within limits, the low probability of an event occurring requiring control room isolation, and the availability of alternate cooling methods.

C.1

In MODE 1, 2, or 3, if the control room area temperature cannot be maintained ≤ 86°F or if the inoperable control room AC subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes overall plant risk. To achieve this status the unit must be placed in at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 3) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES (continued)

ACTIONS

C.1 (continued)

Required Action C.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES

ACTIONS

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

During movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the Required Action and associated Completion Time of Condition B is not met, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require operation of the Control Room Ventilation System in the high radiation mode. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel in the primary and secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the safety analysis. The SR consists of a combination of testing and calculation. The 24 month Frequency is appropriate since significant degradation of the Control Room AC System is not expected over this time period.

With regard to heat removal capability values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 4).

REFERENCES

1. USAR, Section 6.4.

2. USAR, Section 9.4.1.

3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

4. Calculation IP-0-0102.

This page intentionally left blank

BASES (continued)

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture occurring.

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

If the radioactivity rate is not restored to within the limits within the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the overall plant risk is minimized. To achieve this status, the unit must be placed

(continued)

BASES

ACTIONS

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

in at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.3 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 and SR 3.7.5.2

SR 3.7.5.2, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88 (Ref. 5). If the measured release rate of radioactivity increases significantly (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, as required by SR 3.7.5.1, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The required isotopic analysis is intended to support determination of the cause for the increase in offgas radiation release rates, such as the onset of leakage from a fuel pin(s). However, there are certain evolutions (e.g., swapping of the steam jet air ejectors and regeneration of the offgas system desiccant dryers) which are known to result in a predictable and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 and SR 3.7.5.2 (continued)

temporary increase in the indicated offgas radioactivity release rate. These indicated increases in offgas radioactivity release rates can be caused solely by increases in offgas flow. Since these increases are due to an evolution(s) known to cause such an increase and not due to an actual increase in the "nominal steady state fission gas release rate," isotopic analysis of an offgas sample is not required for these evolutions. In any of these cases, it is prudent to ensure that the offgas radiation level (radioactivity release rate) returns to previous or expected levels within four hours or as soon as possible following the evolution. This will confirm that there are no other causes for the increase in the radioactivity release rate indication. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 and SR 3.7.5.2 (continued)

SR 3.7.5.2 is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

With regard to radioactivity rate values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 6).

REFERENCES

1. USAR, Section 15.7.1.
2. NUREG-0800.
3. 10 CFR 100.
4. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
5. NEDE-24810, "Station Nuclear Engineering," Volume 1A.
6. Calculation IP-0-0103.

BASES

ACTIONS

E.1 (continued)

According to Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. This Completion Time assumes complete loss of onsite (DG) AC capability to power the minimum loads needed to respond to analyzed events. In the event Division 3 DG in conjunction with Division 1 or 2 DG is inoperable, with Division 1 or 2 remaining, a significant spectrum of breaks would be capable of being responded to with onsite power. Even the worst case event would be mitigated to some extent—an extent greater than a typical two division design in which this condition represents complete loss of onsite power function. Given the remaining function, a 24 hour Completion Time is appropriate. At the end of this 24 hour period, Division 3 systems could be declared inoperable (see Applicability Note) and this Condition could be exited with only one required DG remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

F.1

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the unit must be brought to MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action F.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

(continued)

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Refs. 3 and 16), Regulatory Guide 1.108 (Ref. 10), and Regulatory Guide 1.137 (Ref. 11).

Where the SRs discussed herein specify voltage and frequency tolerances, the minimum and maximum steady state output voltages of 4084 V and 4580 V respectively, are equal to - 2% and + 10% of the nominal 4160 V output voltage. The specified minimum and maximum frequencies of the DG is 58.8 Hz and 61.2 Hz, respectively, are equal to ± 2% of the 60 Hz nominal frequency. The specified steady state voltage and frequency ranges are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3). However, the minimum voltage was increased to ensure adequate voltage to operate all safety-related loads during a DBA (Ref. 15).

In general, surveillances performed for each of the required DGs are similar, with one notable difference due to the fact that the Division 3 DG utilizes a mechanical governor, while the Division 1 and 2 DGs utilize an electronic governor. As such, the Division 1 and 2 DGs are capable of operating in both an isochronous mode as well as a "droop" mode for when the DGs are paralleled to the offsite source during testing. The Division 3 DG, on the other hand, is capable of operating only in the droop mode (through a droop setting of zero can be utilized). This difference may affect the Division 3 DGs capability to achieve rated frequency following automatic switchover from the test mode to ready-to-load operation upon receipt of a LOCA initiation signal (as verified per SR 3.8.1.17).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

For the Division 1 and 2 DGs, DG operation is returned to the isochronous mode upon switchover such that rated speed/frequency is automatically attained. For the Division 3 DG, however, with the DG governor initially operating in the droop condition during the test mode, operator action may be required to reset the governor for ready-to-load operation at the required frequency. This difference is acknowledged in the Bases for SR 3.8.1.17 to address compliance with that SR. Notwithstanding, the condition also requires the Division 3 DG to be considered inoperable if it cannot be ensured that the required frequency would be attained in the event of a LOCA and a loss of offsite power concurrent with the Division 3 DG being operated or tested with the existing droop setting in effect. Thus, the Division 3 DG is generally considered inoperable while the droop setting is in effect during the performance of SRs that require the DG to be paralleled to the offsite source.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 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 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 have been modified by Notes (the Note for SR 3.8.1.7 and 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. For the purposes of these SRs, the DG may be started using a manual start signal, a simulated loss of offsite power test signal by itself, a simulated loss of offsite power test signal in conjunction with an ECCS actuation test signal, or an ECCS actuation test signal by itself.

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

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 12 seconds. The 12 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 5). The 12 second start requirement may not be applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), 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. Since SR 3.8.1.7 does require 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. Similarly, the performance of SR 3.8.1.12 or SR 3.8.1.19 also satisfies the requirements of SR 3.8.1.2 and SR 3.8.1.7.

In addition to the SR requirements, 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The normal 31 day Frequency for SR 3.8.1.2 (see Table 3.8.1-1, "Diesel Generator Test Schedule") is consistent with the industry guidelines for assessment of diesel generator performance (Ref. 13). 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.

With regard to required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. 17, 18, 19, 22, 23).

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. However, consistent with the recommendations of Regulatory Guide 1.9, Revision 3 (Ref. 16), this surveillance is performed with a DG load equal to or greater than 90 percent of its continuous rating. 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.

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 1.0 is an operational limitation to ensure circulating currents are minimized.

The normal 31 day Frequency for this Surveillance (see Table 3.8.1-1) is consistent with the industry guidelines for assessment of diesel generator performance (Ref. 13).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Note 1 modifies this Surveillance to indicate 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 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test.

Note 3 indicates that this Surveillance shall 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.

With regard to DG loading values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 20).

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the low level alarm setpoint. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at maximum expected post LOCA loads.

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.

With regard to fuel oil level values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 21).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 an 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, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is established by Regulatory Guide 1.137 (Ref. 11). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during 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. It is required to support the 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 design of fuel transfer systems is such that pumps operate automatically in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. Therefore, a 31 day Frequency is specified to correspond to the maximum interval for DG testing.

SR 3.8.1.7

See SR 3.8.1.2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit. The 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject a load equivalent to at least as large as the largest single load while maintaining a specified margin to the overspeed trip.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

The referenced load for DG 1A is the low pressure core spray pump; for DG 1B, the residual heat removal (RHR) pump; and for DG 1C the HPCS pump. The Shutdown Service Water (SX) pump values are not used as the largest load since the SX supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG. The use of larger loads for reference purposes is acceptable. This Surveillance may be accomplished by:

1) Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest load while paralleled to offsite power, or while supplying the bus, or

2) Tripping its associated single largest load with the DG supplying the bus.

As required by IEEE-308 (Ref. 14), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

The 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. 16).

This SR has been modified by two Notes. The intent of Note 1 is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9 (continued)

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

With regard to diesel speed values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 24).

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load, i.e., maximum expected accident load, without overspeed tripping or exceeding the predetermined voltage limits. However, consistent with the recommendations of Regulatory Guide 1.9, Revision 3 (Ref. 16), this surveillance is performed with a DG load equal to or greater than 90 percent of its continuous rating.

The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions.

This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

While the DG is not expected to experience this transient during an event and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

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 ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The 24 month Frequency is consistent with the refuel cycle recommendation of Regulatory Guide 1.9 (Ref. 16) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. The intent of the Note is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failure resulting from offsite/grid voltage perturbations.

This Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite of grid perturbations.

With regard to DG load and voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 24).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 10), 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 Division 1 and 2 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.

With regard to required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. 17, 18, 19).

The DG auto-start 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 has been achieved.

With regard to DG auto-start time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Ref. 22).

The requirement to verify the connection and power supply of permanent and auto-connected 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, systems are not capable of being operated at

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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 the connection and loading of these 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 24 months is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. 16), 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. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. 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 plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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.

With regard to DG start time, required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. 17, 18, 19, 22, 23).

The Frequency of 24 months takes into consideration plant 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. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.14

Regulatory Guide 1.9, Revision 3 (Ref. 16) requires demonstration once per 24 months that the DGs can start and run continuously at or near full-load capability for an interval of not less than 24 hours. The DGs are to be loaded equal to or greater than 105 percent of the continuous rating for at least 2 hours and equal to or greater than 90 percent of the continuous rating for the remaining hours of the test (i.e., 22 hours) (Ref. 16). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube 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 ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

The 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9, Revision 3 (Ref. 16); takes into consideration plant conditions required to perform the Surveillance; 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 above the limit do not invalidate the test. The intent of Note 2 is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

With regard to DG loading capability values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 20).

SR 3.8.1.15

This Surveillance is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(5), and 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.

With regard to DG loading values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 20).

With regard to DG start time, frequency and voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. 17, 18, 19, 22, 23).

The 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9, Revision 3 (Ref. 16).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions (i.e., equal to or greater than 90 percent of the continuous rating) 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 1.108 (Ref. 10), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the DG to each offsite power source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the undervoltage logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

Portions of the synchronization circuit are associated with the DG and portions with the offsite circuit. If a failure in the synchronization requirement of the Surveillance occurs, depending on the specific affected portion of the synchronization circuit, either the DG or the associated offsite circuit is declared inoperable.

The Frequency of 24 months is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. 16), and takes into consideration plant conditions required to perform the Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.17

Demonstration of the test mode override is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(8)and ensures that the DG availability under accident conditions is not compromised as the result of testing. Except as clarified below for the Division 3 DG, interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation 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. 14), paragraph 6.2.6(2), as further amplified by IEEE 387, sections 5.6.1 and 5.6.2. (Clarification regarding conformance of the Division 3 DG design to these standards is provided in the USAR, Chapter 8 (Reference 2).)

Automatic switchover from the test mode to ready-to-load operation for the division 3 DG is also demonstrated, as described above, by ensuring that DG control logic automatically resets in response to a LOCA signal during the test mode and confirming that ready-to-load operation is attained (as evidenced by the DG running with the output breaker open). However, with the DG governor initially operating in a "droop" condition during the test mode, operator action may be required to reset the governor for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

ready-to-load operation in order to complete the surveillance for the Division 3 DG. Resetting the governor ensures that the DG will supply the Division 3 bus at the required frequency in the event of a LOCA and a loss of offsite power while the DG is in a droop condition during the test mode.

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 is 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 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. 16); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. The intent of this note is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident conditions with a loss of offsite power, loads are sequentially connected to the bus by the load sequencing logic (except for Division 3 which has no load sequence timers). The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated and is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(2). Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 24 months is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. 16); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES may perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

With regard to sequence time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 25).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

With regard to DG start time, required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. 17, 18, 19, 22).

SR 3.8.1.20

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

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 10).

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures.

With regard to required voltage and frequency values obtained pursuant to this SR, as read from plant indication

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. 17, 18, 19, 22, 23).

Diesel Generator Test Schedule

The DG test schedule (Table 3.8.1-1) implements the industry guidelines for assessment of diesel generator performance (Ref. 13). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability at > 0.95 per test.

According to the industry guidelines (Ref. 13), each DG unit should be tested at least once every 31 days. Whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is reduced to 7 days. Four failures in 25 valid tests is a failure rate of 0.16, or the threshold of acceptable DG performance, and hence may be an early indication of the degradation of DG reliability. When considered in the light of a long history of tests, however, 4 failures in the last 25 valid tests may only be a statistically probable distribution of random events. Increasing the test Frequency allows a more timely accumulation of additional test data upon which to base judgment of the reliability of the DG. The increased test Frequency must be maintained until seven consecutive failure free tests have been performed.

The Frequency for accelerated testing is 7 days, but no less than 24 hours. Tests conducted at intervals of less than 24 hours may be credited for compliance with Required Actions. However, for the purpose of re-establishing the normal 31-day Frequency, a successful test at an interval of less than 24 hours should be considered an invalid test and not count towards the seven consecutive failure free starts, and the consecutive test count is not reset.

A test interval in excess of 7 days (or 31 days, as appropriate) constitutes a failure to meet SRs and results in the associated DG being declared inoperable. It does not, however, constitute a valid test or failure of the DG, and any consecutive test count is not reset.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. Regulatory Guide 1.9, Revision 2.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. Regulatory Guide 1.93.
7. Generic Letter 84-15, July 2, 1984.
8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
9. 10 CFR 50, Appendix A, GDC 18.
10. Regulatory Guide 1.108.
11. Regulatory Guide 1.137.
12. ANSI C84.1, 1982.
13. NUMARC 87-00, Revision 1, August 1991.
14. IEEE Standard 308.
15. IP Calculation 19-AN-19.
16. Regulatory Guide 1.9, Revision 3.
17. Calculation IP-C-0050.
18. Calculation IP-C-0051.
19. Calculation IP-C-0054.
20. Calculation IP-0-0114.
21. Calculation IP-C-0111.
22. Calculation IP-0-0106.
23. Calculation IP-0-0143.
24. Calculation IP-0-0110.
25. Calculation IP-0-0116.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

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

With regard to fuel oil inventory values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 11).

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of maximum expected post LOCA load operation for each DG. This minimum volume requirement is based on the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG when the DG lube oil sump does not hold adequate inventory for 7 days of maximum expected post LOCA load operation without the level reaching the manufacturer's recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

With regard to lube oil inventory values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 8).

SR 3.8.3.3

The tests of fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between the sample (and corresponding results) of new fuel and addition of new fuel oil to the storage tanks to exceed 31 days. The limits and applicable ASTM Standards for the

(continued)

ACTIONS
(continued)

D.1

If a Division 1 or 2 DC electrical power subsystem is inoperable and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Required Action D.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

E.1

With one or more Division 3 or 4 DC electrical power subsystems inoperable, the HPCS System may be incapable of performing its intended functions and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions of LCO 3.5.1, "ECCS—Operating."

F.1 and F.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to continually charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.20 Vpc or 127.6 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The 7 day Frequency is consistent with manufacturer's recommendations and IEEE-450 (Ref. 9).

With regard to battery terminal voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 13).

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied. This SR provides two options. One option requires that each battery charger be capable of supplying 300 amps for Divisions 1 and 2 (100 amps for Divisions 3 and 4) at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective or the status of the plant during which these demands occur).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is $\leq$ 2 amps.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

With regard to minimum required amperes and duration values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 13).

SR 3.8.4.3

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length are established with a dummy load that corresponds to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is an exception to the recommendations of Regulatory Guide 1.32 (Ref. 10) and Regulatory Guide 1.129 (Ref. 11), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed 18 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test SR 3.8.6.6 in lieu of SR 3.8.4.3. This substitution is acceptable because SR 3.8.6.6 represents an equivalent test of battery capability as SR 3.8.4.3. The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

With regard to battery capacity values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 12).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE Standard 308, 1978.
4. USAR, Section 8.3.2.
5. USAR, Chapter 6.
6. USAR, Chapter 15.
7. Regulatory Guide 1.93, December 1974.
8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
9. IEEE Standard 450, 1995.
10. Regulatory Guide 1.32, February 1977.
11. Regulatory Guide 1.129, December 1974.
12. Calculation IP-0-0123.

BASES

APPLICABILITY (continued)	Inverter requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.8, "Inverters—Shutdown."

ACTIONS

With a required inverter inoperable, its associated uninterruptible AC bus is inoperable if not energized. LCO 3.8.9 addresses this action; however, pursuant to LCO 3.0.6, these actions would not be entered even if the uninterruptible AC bus were de-energized. Therefore, the ACTIONS are modified by a Note stating that ACTIONS for LCO 3.8.9 must be entered immediately. This ensures the uninterruptible bus is re-energized within 8 hours.

A.1

Required Action A.1 allows 7 days to restore an inoperable inverter and return it to service. The 7 day limit is a risk-informed Completion Time based on a plant-specific risk analysis performed to establish this Completion Time for the Division 1 and 2 inverters. This risk has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems that such a shutdown might entail. When the uninterruptible AC bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the uninterruptible AC buses is the preferred source for powering instrumentation trip setpoint devices.

An inverter may be removed from service to perform planned preventive maintenance so long as the inverter is restored to operable status within 24 hours (this is an administrative limit intended to allow preventive maintenance to be performed). The intent of the 7 day limit (i.e., the extended completion time (CT) beyond the initial 24 hours) is to restore an inoperable inverter following an inverter failure (i.e., to support online corrective maintenance).

With a required inverter inoperable, the following compensatory actions will be taken:

1. Entry into Required Action A.1 will not be planned concurrent with Emergency Diesel Generator (EDG) maintenance on the associated train.

2. Entry into Required Action A.1 will not be planned concurrent with planned maintenance on another RPS or ECCS/RCIC actuation logic channel that could result in that channel being in a tripped condition.

These actions are taken because it is recognized that with an inverter inoperable and the instrument bus being powered by the regulating transformer, instrument power for that train is dependent on power from the associated EDG following a loss of offsite power event.

(continued)

BASES

ACTIONS

A.1 (continued)

In addition to the above, the following evaluations will be performed as part of the CPS risk management program whenever inverter maintenance is required.

1. Evaluate simultaneous switchyard maintenance and reliability.

2. Evaluate concurrent maintenance or inoperable status of any of the remaining three instrument bus inverters for the unit.

3. Evaluate simultaneous EDG maintenance.

B.1

If a Division 1 or 2 inverter is inoperable and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Required Action B.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Condiseration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met.

(continued)

BASES

ACTIONS (continued)

C.1

With one or more Division 3 or 4 inverters inoperable, the associated Division 3 ECCS subsystem may be incapable of performing intended function and must be immediately declared inoperable. This also requires entry into applicable Conditions and Required Actions for LCO 3.5.1, "ECCS—Operating."

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

With one RPS solenoid bus inverter inoperable it may be incapable of providing voltage and frequency regulated power sufficient to protect the loads connected to the bus. In this condition, the source of power must be transferred or removed from service. If the RPS bus power is transferred to its alternate source, an additional ACTION is required to periodically monitor the frequency on the bus. This frequency is designed to be limited by the in-line RPS electric power monitoring assembly (required by LCO 3.3.8.2, "RPS Electric Power Monitoring"), however, in the event of a single failure, frequency protection would not be available. Should frequency be discovered < 57 Hz, additional ACTIONS are required in LCO 3.3.8.2 due to the inoperable RPS electric power monitoring assembly.

The 1 hour Completion Time is sufficient for plant personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration, transfer or removal of the RPS bus power supply from service.

E.1

With both RPS solenoid bus inverters inoperable both RPS buses may be incapable of providing voltage and frequency regulated power sufficient to protect the loads connected to the buses. In this condition, the source of power must be transferred or removed from service, however, only one RPS bus is allowed to be powered from an alternate source at any one time. Therefore, at least one RPS solenoid bus must be de-energized. The remaining affected bus will be de-energized or powered from its alternate source in accordance with Condition D.

The 1 hour Completion Time is sufficient for plant personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal of the RPS bus power supply from service.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If the inoperable devices or components cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and uninterruptible AC buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the uninterruptible AC buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

With regard to voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 5).

REFERENCES

1. USAR, Chapter 8.
2. USAR, Chapter 6.
3. USAR, Chapter 15.
4. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
5. Calculation IP-0-0131.

BASES

ACTIONS

C.1 (continued)

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC division could again become inoperable, and DC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

D.1

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, the plant must be bought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS

D.1 (continued)

Required Action D.1 is modified by a Note that prohibits the application of LCO 3.0.4.a. This Note clarifies the intent of the Required Action by indicating that it is not permissible under LCO 3.0.4.a to enter MODE 3 from MODE 4 with the LCO not met. While remaining in MODE 3 presents an acceptable level of risk, it is not the intent of the Required Action to allow entry into, and continue operation in, MODE 3 from MODE 4 in accordance with LCO 3.0.4.a. However, where allowed, a risk assessment may be performed in accordance with LCO 3.0.4.b. Consideration of the results of this risk assessment is required to determine the acceptability of entering MODE 3 from MODE 4 when this LCO is not met. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

With one or more Division 3 or 4 electrical power distribution system(s) inoperable, the Division 3 or 4 powered systems are not capable of performing their intended functions. Immediately declaring the high pressure core spray inoperable allows the ACTIONS of LCO 3.5.1, "ECCS-Operating," to apply appropriate limitations on continued reactor operation.

F.1

Condition F corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

Meeting this Surveillance verifies that the required AC, DC, and uninterruptible AC bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and uninterruptible AC bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

With regard to voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 6).

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.
4. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
5. USAR, Section 8.3.
6. Calculation IP-0-0132.

BASES

BACKGROUND (continued)	fuel assembly in water to ensure that the interlock is activated when the hoist is loaded with fuel. The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).
APPLICABLE SAFETY ANALYSES	The refueling interlocks are explicitly assumed in the USAR analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a rod from the core during fuel loading. The refueling platform location switches activate at a point outside of the reactor core, such that, considering switch hysteresis and maximum platform momentum toward the core at the time of power loss with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core. Refueling equipment interlocks satisfy Criterion 3 of the NRC Policy Statement.
LCO	To prevent criticality during refueling, the refueling interlocks ensure that fuel assemblies are not loaded with any control rod withdrawn. To prevent these conditions from developing, the all-rods-in, the refueling platform position, and the refueling platform main hoist fuel loaded inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

(continued)